nationalgrid

# Stage 03: Workgroup Report

Connection and Use of System Code (CUSC)

# **CMP264:** Embedded Generation Triad Avoidance Standstill
# and
# **CMP265:** Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market

# **CMP269:** Potential consequential changes to the CUSC as a result of CMP264
# and
# **CMP270:** Potential consequential changes to the CUSC as a result of CMP265

What stage is this document at?

| | |
|---|---|
| 01 | Initial Written Assessment |
| 02 | Workgroup Consultation |
| **03** | **Workgroup Report** |
| 04 | Code Administrator Consultation |
| 05 | Draft CUSC Modification Report |
| 06 | Final CUSC Modification Report |

CMP264 aims to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those New Embedded Generators who export on to the system, when determining liability for locational and wider HH demand TNUoS charges.

CMP265 aims to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those embedded generators who are in the Capacity Market who export on to the system, when determining liability for the residual HH demand TNUoS charges.

CM269 aims to amend Section 11 of the CUSC to align any changes introduced under CMP264.

CM270 aims to amend Section 11 of the CUSC to align any changes introduced under CMP265.

This document contains a record of the discussions of the Workgroup which were formed to develop and assess the proposal.

**Published on:**
**Length of Consultation:**
**Responses by:**

***The Workgroup concludes:***

For CMP264 (CMP269) none of the 22 Workgroup members that voted considered that the Original proposal better facilitated the CUSC Objectives. WACM 3 received four out of 22 votes as the better option for facilitating the CUSC Objectives, followed by the baseline and WACM 8 receiving three votes respectively as the better option.

For CMP265 (CMP270) one of the 22 Workgroup members that voted considered that the Original proposal did better facilitate the CUSC Objectives. WACM 10 received four out of 22 votes as the better option for facilitating the CUSC Objectives, followed by the baseline, WACM 3 and WACM 8 receiving three votes respectively as the better option.

*High Impact:*

Suppliers and embedded generators

## Contents



## About this document

This document is a Workgroup Report for CMP264 and CMP265 which details the Workgroup discussion, responses to the Workgroup Consultation and the conclusions of the Workgroup.

An electronic copy of this document can be found via the following links:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP269/

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP270/

## Document Control

**Any Questions?**

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| Version | Date | Author | Change Reference |
|---|---|---|---|
| 1.0 | 20 October 2016 | Code Administrator | Workgroup Report to CUSC Panel |

# 1 Summary of the original Proposals, Terms of Reference and structure of this report

1.1 This document describes the Original CMP264 and CMP265 CUSC Modification Proposals (the Proposal), summarises the deliberations of the Workgroup, responses to the Workgroup Consultation questions, the Workgroup Alternative CUSC Modifications (WACMs) and voting by the Workgroup against the Applicable CUSC objectives.

1.2 As part of the Workgroup analysis for CMP264/265, the Workgroup identified that as these Modifications were charging Modifications (which if approved would require change to aspects of section 14 - Charging Methodologies of the CUSC) there are in fact some references outside section 14 of the CUSC that would require change should CMP264 and/or CMP265 be approved.

1.3 However these could not be addressed via CMP264/CMP265 as these will be assessed against the Applicable Charging Objectives. Consequently Modifications CMP269 and CMP270 have been raised to detail the required changes to Section 11 of the CUSC.

1.4 The CUSC Panel at its August 2016 meeting agreed to align CMP269/270 with CMP264/265 as CMP269/270 were enabling Modifications to support any non-charging changes in the CUSC that may be introduced under CMP264 and/or CMP265.

**CMP264: Generation Triad Avoidance Standstill**

1.5 CMP264 was proposed by Scottish Power and was submitted to the CUSC Modifications Panel for its consideration in May 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the relevant CUSC Applicable Objectives.

1.6 The defect for CMP264 is detailed as the existence of large non-cost reflective Triad avoidance values is likely to distort investment decisions by favouring small generation units over large ones that may be more efficient. This could cause more efficient investments which do not benefit from Triad avoidance to be abandoned or deferred while less effective ones, which do so benefit, go ahead. This would increase total system costs, which is likely to lead to higher costs for consumers. Cost reflective charges would lead to better investment decisions and lower costs for consumers.

1.7 The original solution to this defect is to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those New Embedded Generators who export on to the system, when determining liability for locational and wider HH demand TNUoS charges. The proposal is to apply until such as time as Ofgem has completed its consideration of the current electricity Transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented.

1.8 Following the Workgroup Consultation, as summarised in this report, the Original Proposal and 15 Workgroup Alternative CUSC Modifications (WACMs) were brought forward.

**CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market**

1.9 CMP265 was proposed by EDF Energy and was submitted to the CUSC Modifications Panel for its consideration in May 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the relevant CUSC Applicable Objectives.

1.10 The defect for CMP265 is detailed as charging demand on a net basis means that some of the gross HH demand will not pay the residual, and neither will the embedded generation that nets off that demand. The effect of the net demand charging basis is thus that the value of the demand residual charge element is credited to the embedded generation, where there is an association with an embedded generator as part of that Supplier’s portfolio in that GSP group. This is not cost-reflective, as there is no logical reason for that credit, which is growing, to be given.

1.11 The original solution to this defect is to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those embedded generators who are in the Capacity Market and export on to the distribution network, when determining liability for the residual HH demand TNUoS charges.

1.12 Following the Workgroup Consultation, as summarised in this report, the Original Proposal and 14 Workgroup Alternative CUSC Modifications (WACMs) were brought forward.

1.13 Due to the commonality between the workgroup discussions, the similarity in topics and for ease of use the Workgroup has prepared a single Workgroup Consultation document but will be treated separately by the CUSC Panel.

**Terms of Reference**

1.14 The CUSC Panel detailed in the Terms of Reference the scope of work for the CMP264/CMP265 Workgroups and the specific areas that the Workgroup should consider. The table below details these specific areas and where they are referenced in this report. The full Terms of Reference can be found in Annex 2.

1.15 For CMP264 urgency was not requested but accelerated timescales were set such that a decision could be achieved by December 2016 to be in advance of the Capacity Market auction. The CUSC Panel agreed to accelerated timescales.

1.16 For CMP265 the Proposer requested urgency as it considered that if not urgently addressed it may cause a significant commercial impact on parties, consumers or other stakeholder(s). As the next Capacity Market auction (for winter 2020/21) takes place in December the present arrangements give an artificial advantage to Embedded Generators, distorting the capacity market. The CUSC Panel in its deliberations did not consider that it should be granted urgency as the Modification was considered complicated and could not be addressed fully by the Workgroup using an urgent process. It considered that following an urgent timetable holds an inherent risk of unintended consequences, which may arise due to there being insufficient time for all aspects of a Modification Proposal to be considered. Ofgem[1] agreed with the CUSC Panel's assessment that urgency should not be granted but that an accelerated timetable should be followed.

1.17 The original date for providing the final report to the Authority for decision was 12 October 2016. The Workgroup requested a month extension to allow for further meetings and discussion to be had, whilst remaining on an accelerated timetable and supporting submitting the final report to the Authority no later than 28 November 2016.

1.18 It is part of the standard CUSC modification process for the statement of the defect to be within the gift of the proposer who has identified said defect and determined a possible modification (solution) to address the defect. It was noted that several of the requests for Workgroup alternatives that were submitted to the Working Group provided solutions that were wider than the scope of the defect in that they had an impact outside of the triad benefit to embedded generators. The workgroup had discussed the scope of the defect prior to its consultation (see section 3.2 of the workgroup consultation) and acknowledged the narrow nature of the defect and proposed solution. At the time of the workgroup consultation the workgroup has not agreed on a definitive view of the defect.

1.19 As part of discussions held to narrow down the number of alternatives to be an efficient way forward (as directed by the workgroup terms of reference) the workgroup acknowledged that

[1] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/
Proposal section contains the letter from the CUSC Panel and Ofgem on the urgency request

any proposals which altered the structure of demand TNUoS tariffs would be out of scope of these modifications. See also section 7.12 of this report for more on this matter.

Table 1: CMP264 ToR

**CMP264**

| Specific area | Location in the report |
| --- | --- |
| a) The Workgroup should consider whether, on the balance of probabilities, the current level of embedded generation triad avoidance benefit significantly exceeds the actual avoided transmission investment cost, whether this causes a distortion in competition, and whether the proposed temporary removal of such benefits (pending the outcome and implementation of Ofgem's considerations) would better meet the code objectives. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis and time spent due to the accelerated timescales. |
| b) The Workgroup should not attempt to resolve the issue of what the most appropriate charging arrangements should be on an enduring basis, as this will be the subject of Ofgem's considerations. | The Workgroup did not consider the issue of what the most appropriate charging arrangements should be. |
| c) The Workgroup should consider the definition of and criteria for the "disapplication date" in the proposed solution, i.e. the date on which the modification would cease to have effect. | N/A as the Proposer removed disapplication date. Refer to section 3.9 |
| d) The Workgroup should consider whether the Workgroup's conclusions would be materially impacted by the length of time between implementation and the "disapplication date". | N/A as the Proposer removed disapplication date. Refer to section 3.9 |
| e) The Workgroup should consider consumer impacts resulting from the proposal. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis and time spent due to the accelerated timescales. |
| f) Consider any link to the Balancing and Settlement Code with particular focus on timescales of any changes. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis. The BSC Modification P348[2] and P349[3] Workgroups shared a number of Workgroup members with CMP264/265. In addition a BSC representative attended CMP264/265 as an observer. |
| g) Consider any link to EMR Settlements metering with particular focus on timescales of any changes. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but |

[2] https://www.elexon.co.uk/mod-proposal/p348/

[3] https://www.elexon.co.uk/mod-proposal/p349/

| | |
|---|---|
| | with limited analysis and time spent due to the accelerated timescales. |

Table 2: CMP265 ToR

**CMP265**

| Specific area | Location in the report |
|---|---|
| a) This Workgroup should not focus on transmissions connected generators in negative zones. | The Workgroup did not consider the issue of transmission connected generators in negative zones. |
| b) The Workgroup should not look to amend the existing Capacity Mechanism. | The Workgroup did not consider amending the existing Capacity Mechanism. |
| c) The Workgroup should consider all Embedded Generation with Capacity Market contracts directly or indirectly. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis and time spent due to the accelerated timescales. |
| d) The Workgroup should consider consumer impacts resulting from the proposal. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis and time spent due to the accelerated timescales. |
| e) The Workgroup should consider whether, on the balance of probabilities, the current level of embedded generation triad avoidance benefit significantly exceeds the actual avoided transmission investment cost, whether this causes a distortion in competition, and whether the removal of such benefits (pending the outcome and implementation of Ofgem's considerations) would better meet the code objectives. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis and time spent due to the accelerated timescales. |
| f) Consider any link to the Balancing and Settlement Code with particular focus on timescales of any changes. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis. The BSC Modification P348 and P349 Workgroups shared a number of Workgroup members with CMP264/265. In addition a BSC representative attended CMP264/265 as an observer. |
| g) Consider any link to EMR Settlements metering with particular focus on timescales of any changes. | Workgroup consultation Report contains evidence (please refer to volume 2 of this report). The Workgroup noted that it had been considered but with limited analysis and time spent due to the accelerated timescales. |

**Structure of the report**

1.20 The main body of this report is split into 14 sections and 4 annexes. In additional there will be 5 volumes to this report.

**Sections:**

1. Section 1: summarises the original proposals, where the Terms of Reference have been met in the report and the structure of this report.
2. Section 2 is a summary to date.
3. Section 3 goes through a high level overview of the original defects proposed under CMP264 and CMP265.
4. Section 4 covers the questions posed in the Workgroup Consultation.
5. Section 5 covers responses to Workgroup Consultation questions.
6. Section 6 covers analysis provided by the Workgroup members post the Workgroup Consultation.
7. Section 7 covers the features contained in alternative options.
8. Section 8 covers key themes within alternatives proposed.
9. Section 9 covers WACMs and voting on an alternative to a Workgroup Alternative CUSC Modification (WACM).
10. Section 10 covers the approach to legal text changes to the CUSC.
11. Section 11 covers the voting by the Workgroup.
12. Section 12 summarises the conclusions of the Workgroup.
13. Section 13 covers the impacts and assessment.
14. Section 14 covers the proposed implementation and Transition arrangement.

**Annexes**

1. Annex 1 contains the CUSC Proposals forms for CMP264, CMP265, CMP269 and CMP270
2. Annex 2 contains the Terms of Reference for CMP264, CMP265, CMP269 and CMP270
3. Annex 3 contains the attendance register
4. Annex 4 contains the draft legal text changes

**Volumes**

1. Volume 1 is this report

2. Volume 2 contains the Workgroup Consultation report that was issued in 2 August 2016.

3. Volume 3 contains the all the responses received to the Workgroup Consultation report questions and with page references for each respondent.

4. Volume 4 contains the voting statements by Workgroup members, with page references for each respondent.

5. Volume 5 contains presentations from Workgroup members post Workgroup Consultation.

# 2 Summary of progress to date

2.1 The Workgroup initially met five times to discuss and clarify the defects and the proposed rectification approach. The output from these meetings resulted in the Workgroup Consultation report which was issued in August 2016. The report detailed the work performed to date; the alternative options a number of Workgroup members had raised and posed a number of questions to respondents.

2.2 CMP264 received **47** responses and CMP265 received **46** responses to the questions posed. A number of the respondents provided views on the specific alternatives contained in the report and also proposed alternative ideas. The Workgroup Consultation Report that was issued is contained in **volume 2** of this report.

2.3 The Workgroup has subsequently met seven times to review the responses to the questions and work through the options for WACMs. At its meeting on 19 September the Workgroup voted on which options should become WACMs. In addition the Workgroup Chair also considered that **29** of the alternatives (across both CMP264 and CMP265) to be better than the baseline and facilitates the CUSC charging objective (a) of "That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity". The Chair considers that the requirement to retain these additional WACMs reflects the composition of the Workgroup and the variety of views. This will allow the CUSC Panel and ultimately the Authority to be provided with a wide range of alternatives that reflects the views of the Workgroup to meet the defects described. This is detailed in sections 6 & 8.

2.4 On 5 October the Workgroup met to vote on which whether the original Proposals or any of the WACMs would be better than the baseline of the CUSC. This is detailed in section 9.

## 3 High level overview of the original defects proposed under CMP264 and CMP265

3.1 CMP264 aims to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those New Embedded Generators who export on to the system, when determining liability for locational and wider HH demand TNUoS charges.

3.2 CMP265 aims to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those embedded generators who are in the Capacity Market who export on to the system, when determining liability for the residual HH demand TNUoS charges.

**CMP264: Generation Triad Avoidance Standstill**

3.3 CMP264 was proposed by Scottish Power and was submitted to the CUSC Modifications Panel for its consideration in May 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the relevant CUSC Applicable Objectives.

3.4 The defect CMP264 attempts to address is changing the Transport and Tariff Model and billing arrangements to remove the netting of output from those New Embedded Generators who export on to the system, when determining liability for locational and wider HH demand TNUoS charges. The proposal is to apply until such as time as Ofgem has completed its consideration of the current electricity Transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented. The original proposal had an implementation date of 1 April 2017.

3.5 Following the Workgroup Consultation, as summarised in this report, the Original Proposal and 15 Workgroup Alternative CUSC Modifications (WACMs) were proposed.

**CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market**

3.6 CMP265 was proposed by EDF Energy and was submitted to the CUSC Modifications Panel for its consideration in May 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the relevant CUSC Applicable Objectives.

3.7 The defect CMP264 attempts to address is changing the Transport and Tariff Model and billing arrangements to remove the netting of output from those embedded generators who are in the Capacity Market and export on to the distribution network, when determining liability for the residual HH demand TNUoS charges. The original proposal had an implementation date of 1 April 2020.

3.8 The table 3 below summarises the key features in each of the original Proposals.

**Table 3:** Comparison of the Original CMP264 and CMP265 proposals

| | CMP264 Original Proposal | CMP265 Original Proposal |
|---|---|---|
| **Proposer** | Scottish Power | EDF Energy |
| **Proposal** | Do not deduct New Embedded Generation from a suppliers' charging volumes, for the purposes of demand TNUoS. Thereby, removing demand TNUoS embedded benefit for those New Embedded Generators. | Do not deduct certain embedded generation (those with Capacity Market agreements[4]) from a suppliers' charging volumes, for the purposes of demand TNUoS. Thereby, removing demand TNUoS embedded benefit for those embedded generators. |
| **Affected Embedded Generators who have a different value of the embedded benefit under the proposal** | Embedded generators defined as "New" after 30 June 2017 | All Embedded Generators with a Capacity Market agreement. |
| **Demand TNUoS Embedded benefit for the affected generators[5]** | New Embedded Generators will receive no demand TNUoS embedded benefit (neither the locational nor the residual) | Affected Embedded Generators would receive the locational demand TNUoS tariffs as an embedded benefit, but not the demand residual. |
| **Implementation Date (for changes to charging methodology)** | 1 April 2017 (please refer to Table 9 )<br>The first affected volumes would be for "new embedded generators" during the 2017/18 November – February Triad season. | 1 April 2020 |
| **Disapplication** | Intended as a 'stop-gap' solution until Ofgem confirms that it has completed its consideration of the issues (and any review which may ensue) and any resulting changes have been fully implemented. (See section 3.9) | No. Enduring solution, unless superseded by an implemented outcome of Ofgem/Grid wider review of charging arrangements that has effect in the same area of the CUSC. |
| **Related BSC Modification** | P349 – Facilitating embedded generation Triad Avoidance Standstill | P348 - Provision of gross BM Unit data for TNUoS charging |

### Amendments to the original CMP264 proposal and removal of the Disapplication Date

3.9 During discussion within the Workgroup, the Proposer for CMP264 has amended the Original Proposal to remove the Disapplication Date. The reasoning behind this was that as it was not possible to predict when a review will take place or indeed what the

[4] CM agreements are commonly described as contracts throughout this report

[5] For SVA registered embedded generators (the majority) the embedded benefit is paid through the supplier, so any changes affect supplier TNUoS charges and so the embedded generator indirectly. For CVA registered embedded generators the demand TNUoS embedded benefit is received directly from National Grid.

recommended changes would be/get implemented. This could present problems in defining a Disapplication Date in terms of a specified action by the Authority in the CUSC legal text.

3.10 The Workgroup did discuss an alternative option of defining a firm Disapplication Date but considered that this too was also problematic as the timetable for Ofgem's review and the Modification process which could potentially follow is uncertain. Too short a Disapplication Date could lead to a hiatus between the disapplication of CMP264 and the implementation of Ofgem's conclusions. Too long a Disapplication Date (e.g. in 2026) leaves the provisions subject to the normal modification process and would be in effect meaningless.

3.11 Furthermore it was recognised that the use of a firm Disapplication Date could in no way bind Ofgem to a date for concluding the review and implementation the conclusions.

3.12 On this basis, while continuing to emphasise the intended temporary nature of CMP264, the Proposer has concluded that formal provisions for a Disapplication Date would add little in practice to the proposed Modification. Accordingly, it has decided not to include Disapplication Date provisions in the Original proposal.

# 4 Questions included in the Workgroup Consultation Report

4.1 Volume 2 of this report contains the full Workgroup Consultation Report and should be read in conjunction with this report. The Workgroup Consultation was issued 2 August 2016, with responses to be received by 24 August 2016.

4.2 The Workgroup in addressing which questions to should be included in the Workgroup Consultation Report considered what information they were seeking directly for CMP264 or CMP265 or those that could be considered to be shared by both Modifications.

**CMP264**

4.3 The specific questions the Workgroup wanted to understand the views of industry on the 'cut-off' date and definition for those plants that would be classed as 'new Embedded Generation' under the Modification. They also wanted to understand if the date proposed for implementation would be appropriate and if not why. The Modification may introduce a loophole due to the fact that it didn't consider behind the meter or mixed sites and industry views were canvassed on what its views would be regarding a loophole. The Workgroup were also keen to understand what value (if any) industry considered should be appropriate for Embedded Benefits and why.

**CMP265**

4.4 The specific questions the Workgroup wanted to understand what the implications (if any) would be in respect of mixed sites and what category of Capacity Market CMU should be captured under the Modification.

**CMP264 and CMP265 shared questions**

4.5 For the shared questions the Workgroup wanted to understand from Suppliers whether charges were set as to the same tariff that National Grid charges on demand customers to understand how embedded benefits were passed through to Embedded Generators. The Workgroup wanted to understand what industry considered to the value of Embedded

Generation output and demand side reduction for the 2016/2017 Triad season and whether the values included in the report seemed a fair reflection.

4.6 The Workgroup also wanted to understand what the impact of the demand TNUoS Embedded Benefit may have on decisions relating to the Capacity Market and whether both the locational and residual component of the demand TNUoS should be removed as an embedded benefit (as CMP264 Original) or just the residual component (as CMP265 Original) or some other method

4.7 In addition the standard consultation questions were included for both CMP264 and CMP265 to understand what support or concerns there was from industry in respect of whether the original proposals or any of the associated potential options for change better facilitates the Applicable CUSC Objectives, what implementation date implications may be and whether the respondent wanted to raise an alternative for consideration by the Workgroup.

4.8 It was also noted by Workgroup members that Ofgem had issued its open letter[6] at the time of issuing the Workgroup Consultation Report (the letter was issued 29 July 2016 with a close date of 23 September 2016 for comments). A number of parties indicated to National Grid's Code Administration team that they would not be responding to the CMP264/265 Workgroup Consultation but rather respond to Ofgem's open letter.

## 5 Summary of responses to Workgroup Consultation questions

5.1 This section summarises the views of the Workgroup and the Industry that were provided after the Workgroup Consultation responses were received to the Standard Workgroup Consultation questions and the specific questions posed for each Modification. The standard first four questions of the Workgroup Consultation request views on whether the two proposals meets the applicable CUSC Objectives, if the implementation approach is supported and general comments including the requirement of any potential WACMs.

5.2 The responses to the question of whether the Original Proposal better facilitates the applicable CUSC Objectives revealed that for:

**CMP264:**

5.3 **Six of the 47** respondents supported the proposal (including a response from the Proposer's organisation) and believed it did better meet Objective (a). In addition two respondents were unable to confirm if they believed it did or not as there wasn't enough analysis provided to make this decision. The general view of these respondents was they believed that the Modification introduced discrimination and concerns around investment decisions made or being made and that a wider review should be performed.

**CMP265:**

5.4 **Seven of the 46** respondents supported the proposal (including a response from the Proposer's organisation) and believed it did better meet Objective (a). In addition three respondents were unable to confirm if they believed it did or not as there wasn't enough analysis provided to make this decision. The general view of these respondents was they believed that the Modification introduced discrimination and concerns around investment decisions made or being made and that a wider review should be performed.

5.5 A number of the respondents highlighted that **both** Proposals fail to address the wider issues associated with the defect for existing generators and also introduces discriminatory treatment between new and existing generation (which in their views continues to receive

6 https://www.ofgem.gov.uk/system/files/docs/2016/07/open_letter__charging_arrangments_for_embedded_generation.pdf

the growing Triad benefit). There were also a number of views raised about the accelerated timescales and that a partial and potentially discriminatory solution may result in creating more uncertainty into the electricity market.

5.6 Whilst reviewing these responses, the Workgroup also noted that there was support from the industry for a wider review to take place to allow sufficient time for full analysis to be performed.

5.7 A summary of the key themes in responses can be found in tables 4 to 6 below. The full responses by all respondents (excluding any where the respondent has requested it is not published for confidentiality reasons) can be found in Volume 3 to this report.

**Table 4: CMP264 specific questions**

| Question No from Consultation | Question | High-level summary of views from the respondents |
|---|---|---|
| 1 | Do you believe that CMP264 Original proposal or either of the associated potential options for change better facilitates the Applicable CUSC Objectives? | Refer to comments in 5.3 & 5.5 |
| 2 | Do you support the proposed implementation approach for CMP264? Are the suggested implementation timescales suggested for CMP264 appropriate / achievable? | Refer to comments in 5.3 & 5.5 |
| 3 | Do you have any other comments for CMP264? | Refer to comments in 5.3 & 5.5 |
| 4 | Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider for CMP264? | A number of options were put forward; these are covered in sections 6 and 8. |
| 10 | i) Do you think a cut-off date for "new embedded generation" of 30 June 2017 is appropriate? What other date would you propose? | The majority of respondents did not consider that this would be sufficient time to allow those that hold CM contracts to consider the investment implications and also the time frame for any system changes.<br><br>A smaller number of respondents did consider the timeframe to be acceptable but did voice some reservations about the speed to which a system solution could be implemented.<br><br>Some respondents supported grandfathering and others did not. |
| | ii) Do you have any views on how mixed sites are being addressed in CMP264 Original? | With respect to mixed sites the responses were concerned that no 'loopholes' were introduced but agreed that the approach would be a pragmatic one until a wider review was undertaken. |

| | | |
|---|---|---|
| | iii) Do you think new-build embedded generation capacity that has entered into long term financial and performance commitment obligations via 2014 and 2015 capacity market or contracts for difference auctions (prior to this modification proposal) should be given exceptions to this cut-off date? | The responses were mixed in opinion with some answering yes to support investor confidence. Those that indicated no based this on the view that that projects should be advanced enough for construction and commissioning before the cut-off date or that a non-cost reflective payment should be made continuously |
| | iv) Do you agree that ignoring demand behind the meter is unlikely to create a significant "loophole" or material discrimination risk in relation to the CMP264 arrangements in the short term | Concerns were raised that a loophole may be created and that this in itself may be considered discriminatory; others took the view that the loophole would be small and shouldn't be used as a mechanism to delay the Modifications. |
| | v) Question to suppliers: Do you consider that the wording of your existing contracts allow you to reflect the changes provided by these modifications in a cost reflective manner. For example, these changes will apply to existing PPAs and generators who significantly alter their output (EREC 59). | The majority of responses indicated no comment (as either not Suppliers or not wanting to make information public). A number indicated that they would have flexibility to amend contracts, whilst the counter view was received from others that they had locked in contracts that couldn't be amended in timescales proposed. |
| | vi) Do you agree with the definition of commissioned and do you agree that it is appropriate? If you do not agree with the definition or that it is appropriate please provide alternative definitions and rationale for this definition | Again the majority did not provide comments but a number indicated that they agreed with the definition whilst others considered that the definition may introduce distortions. |
| 13 | Do you have a view of whether implementation for the 2017/18 Triad season is sufficient to allow changes for:<br>i) supplier contracts and billing system; and<br>ii) for other stakeholders? | The predominant sense from responses for both elements was that more time would be needed to allow for system development and time for the industry to accommodate to the changes. |
| 18 | Do you have a view if embedded benefits are frozen at a non-zero value, what should that value be as a £/kW tariff (2016/17 value is £45.33 / kW)? | For those that were not supportive of the Modification there was a strong view that they should be frozen to provide the stability to allow investments to deliver security of supply.<br>There were a number of counter |

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| | | views that Embedded Generation tariffs should be broadly equivalent in value to the tariffs applying to Transmission Connected Generators in similar locations. Because transmission connected generator tariffs can (and should) change over time, freezing tariffs for any embedded generation at any level would work against cost reflectivity and effective competition in generation. |

**Table 5 CMP265 specific questions**

| Question No from Consultation | Question | Views from the respondents |
|---|---|---|
| 5 | Do you believe that CMP265 Original proposal or either of the associated potential options for change better facilitates the Applicable CUSC Objectives? | Refer to comments in 5.3 & 5.5 |
| 6 | Do you support the proposed implementation approach for CMP265? Are the suggested implementation timescales suggested for CMP265 appropriate / achievable? | The majority of respondents were concerned with the implementation timescales and the interaction with the Capacity Market and those plants that had prequalified and 'opted in' to the CM auction and that were unable to withdraw as CMUs price takers.<br>It was noted that so as not to affect existing DG CMUs already prequalified for this years CM then the decision would have to be made by Ofgem (and communicated widely) by no later than Friday 18th November to enable prequalified existing DG to make an informed opt out/in decision for the T-4 2016 CM add that auction and date that is (commence 6 Dec). |
| 7 | Do you have any other comments for CMP265? | Refer to comments in 5.3 & 5.5 |
| 8 | Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider for CMP265? | A number of options were put forward; these are covered in sections 6 and 8. |

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| 11 | *i)* Views are sought on the implication for mixed sites discussed in 3.4.10.{*Workgroup Consultation Report reference}*<br>ii) Views are sought on the preference of categories of capacity Market CMU captured by this proposal, please indicate your preference from the following list and reasons:<br>• All existing and new distribution generation CMUs<br>• All existing and new distribution generation CMUs and DSR CMUs (proven and unproven)<br>• All price maker CMUs<br>• All newbuild/prospective distribution generation CMUs only (defined as >1year contracts) | It was the overwhelming view that the level of complexity would be prohibitive.<br>The majority view of those that did respond to this question that it should be all Embedded CMUs with a CM contract that should be considered in scope as having selective capacity market CMUs may risk distorting the CM clearing prices and creating perverse incentives for certain categories of CMU. Indeed other noted that it should apply to all Embedded Generators and not just those that hold a CM contract.<br><br>This view was countered in the respect that if a CMU was a price-taker they would be unable to influence the clearing price or distort the CM outcome.<br><br>A number of respondents and Workgroup members also raised the issue of secondary trading. This is addressed in section 10.6 |
| 14 | Do you have a view of whether implementation for the 2020/21 Triad season is sufficient to allow changes for i) supplier contracts and billing system, and ii) for other stakeholders? | Whilst a number of respondents agreed that there would be sufficient time this was caveated with the view of not supporting the Modification. |

**Table 6: Questions posed for both CMP264 and CMP265**

| Question No from Consultation | Question | Views from the respondents |
|---|---|---|
| 9 | i) Suppliers: In setting charges for your demand customers, do you charge them at the same tariff as National Grid charges you (i.e. gross), to enable you to pay the embedded benefit to embedded generators, or please explain the way in which it is funded?<br>ii) Suppliers: Does the estimate that 7.58GW of embedded generation output and 2.5GW of demand side reduction at the time of Triad for 2016/17 seem reasonable based on your knowledge of the UK market? If not what is your estimate of embedded generator | Due to the commercially sensitive nature most responses had no comment or were not Suppliers.<br>One response indicated that the analysis undertaken in the Cornwall and KPMG reports provides a robust estimate of the total de-rated DG capacity that reduces Transmission demand, estimates of demand side reduction are harder to |

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| | output and DSR at time of Triad? | ascertain. NG's estimates of Customer Demand Management (CDM) indicated a similar level of participation. |
| 12 | Can you identify – either quantitatively or qualitatively - the impact of the demand TNUoS embedded benefit on your decisions made in making capacity market decisions? | Due to commercial considerations no detail was provided but the majority did note that they would expect the bid price into the CM to raise accordingly if either Modification was approved.<br>A number of responses did provide information such as new-builds in the 2014 and 2015 CM had 100% priced in Triad Embedded Benefits into their CM prices and assumed this would continue without major reform given the regulatory stability and the recent decisions in the NG informal embedded benefits review (the NG decision not to change Triad in 2014 specifically references to 'protect investor confidence). |
| 15 | i. What are your views on the 2 broad options to enable the reporting of gross export metered data?<br>ii) Would you have the data available required for Option B (both CMP264 and CMP265) for both new contracts and existing contracts where a customer may be partially exempt?<br>iii) Do you believe you can implement the proposed changes by the respective implementation dates?<br>iv) What are the pros and cons of the 2 proposals that ELEXON are considering to implement this (P348 for CMP265/ P349 for CMP264)? | The majority of respondents did not provide information; of those that did there was a split in those that consider a Supplier best placed and those that would rather have the data provided via ELEXON. |
| 16 | Do you have any further evidence / comments on the consumer impact of changing the demand TNUoS embedded benefit in either the short-run or long-run? | The overall majority view was that a wider review should be undertaken and that concerns were raised over security of supply during the Triad period.<br><br>A number noted that the value of embedded benefit payments to generators due to the net |

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| | | charging of the Demand Residual represented a very high cost to customers and that the removal of this benefit would result in a substantial direct reduction in cost to customers. It was also noted that this customer saving may be offset to some degree by higher prices in the wholesale power market and higher clearing price of the Capacity Market. |
| 17 | Do you feel that both the locational and residual component of the demand TNUoS should be removed as an embedded benefit (as CMP264 Original) or just the residual component (as CMP265 Original) or some other method? | The majority of respondents considered that neither should be removed. A number highlighted that they considered that a wider review be undertaken on all aspects of demand TNUoS and related Embedded Benefits as part of a comprehensive review of network system charging, taking full account of expected developments in system operation, future generation mix and behaviour of demand-side participants. This, it was felt, would best be undertaken as a Significant Code Review.<br>A number of respondents did consider that locational element should remain, with a £x value for the Embedded Benefit. |
| 19 | Regarding the proposed alternatives what are your views on the suggested implementation dates? Are these achievable? Please give reasons for your view. | As highlighted before all respondents cautioned ‘rushing’ the solution and implementation date. By extending the implementation date out this would allow the processes and systems to be considered and implemented. |

## 6 Analysis provided by Workgroup members post the Workgroup Consultation

6.1 Post the Workgroup Consultation a number of the Workgroup members provided presentations to the Workgroup on the alternatives they were proposing and the impact on Suppliers. These are contained Volume 5 to this report.

## 7 Features contained in alternative options

**Background**

7.1 The Workgroup considered alternative methods for providing TNUoS embedded benefit. Presently, TNUoS embedded benefit is paid in relation to demand TNUoS charges. Specifically it is associated with charges for demand metered through half hourly (HH) meters. These charges are levied against the average level of HH metered demand which occurs over the "triad". The triad refers to the three settlement periods of highest transmission system demand within a charging year. It consists of the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 clear days, between November and February inclusive of the charging year concerned.

7.2 TNUoS embedded benefit is realised in respect of exports from exemptible embedded generation, which is generally generation connected to a distribution network which does not need a generation licence to operate. It is realised in one of two ways depending on how the affected embedded generator is registered in central settlement systems. An embedded generator can be registered in one of two settlement processes: the Supplier Volume Allocation (**SVA**) or the Central Volume Allocation (**CVA**) systems.

7.3 If a generator's meter is registered in SVA then a supplier tends to take responsibility for its exports of power onto the system for the purposes of settlement. The export is treated as negative demand in the calculation of that supplier's demand for a particular demand charging area, so that when the generator generates during the triad period it reduces the supplier's exposure for demand TNUoS charges.

7.4 This is referred to as "**net charging**" as it is the level of net demand during the triad which is charged demand TNUoS. For example, a supplier with 150MW of SVA demand and with 50MW of SVA registered embedded generation on average over the triad in a particular zone would be charged on the net level of 100MW. Under this "net charging" arrangement, embedded generation is seen to reduce metered peak demand which ultimately signals transmission investment need.

7.5 If an embedded generator is registered in the CVA arrangements, the party which has registered it is paid the negative demand TNUoS directly for any output generated during the triad period. That is, it doesn't need to offset any demand to realise the benefit. A supplier or the generator could be responsible for registering the generating station in the CVA arrangements. Suppliers that receive embedded benefits on behalf of generation that they have registered in settlement tend to pass most or all of this benefit to the generators concerned through the contractual arrangements they have with them.

7.6 Regardless of the route through settlement, the value of embedded benefit is effectively the negative demand tariff for the relevant zone. That is, instead of the demand tariff being a payment from the supplier to National Grid, for the embedded benefit the payment flows in the opposite direction.

7.7 The demand tariff is split into two elements: the "**locational charge**" and the "**residual tariff**". The locational charge is the collective term used within the CUSC to describe two individual charges, the "**peak**" and "**year round**" charges, which vary by location and are designed to reflect the costs of capital investment in, and the maintenance and operation of, the transmission system. The residual tariff does not vary by location and is designed to ensure that the correct revenue is recovered overall.

**Alternative Approaches**

7.8 The Workgroup Consultation report included information on five alternatives options for the treatment of embedded generation and also questions relating to areas that should be considered in pulling together an alternative option.

7.9 For CMP264 and CMP265 eight respondents provided alternatives. From these the Workgroup developed a matrix of features that could be included in any alternatives. Each alternative request was discussed in the Workgroup to ensure that a common understanding was held by all.

7.10 The Workgroup initially considered what could be potential features, recognising that there were multiple permutations and that the discussions that the Workgroup undertook had evolved such that some of the ideas to address the defect had wider impacts than originally envisaged.

**Grandfathering:**

The Workgroup considered grandfathering to mean an arrangement which preserved a higher level of Embedded Benefit compared with those that are not grandfathered Generators.

Grandfathering options could range from:

- No grandfathering
- Grandfathering existing, with different cut-off dates
- Grandfathering existing, plus those with existing CM/CFD agreements, with different cut-off date for grandfathering
- Grandfathering existing, plus those with existing CM/CFD agreements but no cut-off date
- Grandfathering all except existing CM agreements
- Grandfathering all except existing CM/CFD agreements
- Grandfathering all except existing CM/CFD agreements or CHP generators

**New Embedded Benefit:**

Alternative options for calculating the embedded benefit were considered. Alternatives to both elements which make up the current embedded benefit, the demand locational charge and the demand residual charge, were considered.

**a) Alternatives to the Locational Charge**

This could range from:

- No locational element
- Peak plus year round (as now)
- Peak only

**b) Alternatives to the Residual Charge**

This could range from:

- Zero £
- Using the Cornwall Energy value of c £32
- Using the value at the date of the last Embedded Benefits Review £27
- Using the 2015/16 value + RPI
- Using the 2016/17 value + RPI

- Using the Generation Residual[7]
- Using an approach of avoided infrastructure + avoided Transmission Network connection costs
- Using the average of the past [four] years
- Using a local reinforcement credit, wider reinforcement credit, generation residual (if negative)
- No change

**Floor to avoid negative tariffs:**

The Workgroup considered whether or not it was desirable to have a floor to the total level of Embedded Benefit an Embedded Generator was exposed to. The aim of this was to address concerns that a negative level of Embedded Benefit may lead to a generator not generating at times of peak demand simply to avoid paying a significant negative charge. The majority felt a floor would be appropriate but some felt it would not.

**Charging base for Embedded Generators**

Presently demand charges are levied over the triad period, but there are alternative periods over which they could be recovered/paid out.

Options considered were:

- Triad – no change
- Using 16:30 to 19:30 for November, December and January and 17:00 to 20:00 in February
- 16:00 to 19:00 Year Round

**Implementation Date:**

In this instance, the Workgroup meant the point at which the new charges would take effect, rather than when the new text to the CUSC would be implemented. Options considered were:

- 2017/2018
- 2018/2019
- 2020/2021
- A phased implementation

7.11 It was acknowledged by Workgroup Members that this gave rise to an excessive number of potential workgroup alternatives and therefore these were developed into key themes each of which is explained below.

7.12 As part of discussions held to narrow down the number of alternatives to be an efficient way forward (as directed by the workgroup terms of reference) the workgroup acknowledged that any proposals which altered the structure of demand TNUoS tariffs would be out of scope of these modifications. This aligns to the discussions held by the workgroup where a narrow defect should be addressed by any solutions, focused on the Triad TNUoS benefits for embedded generators. However, some workgroup members felt that this was a constraint as it precluded solutions which would otherwise have been more consistent with the underlying objectives of CUSC and could therefore have been more optimal.

[7] For example if a Transmission Connected Generator receive a credit of £2 per kw Embedded Generators would also get a credit of £2 per kw

## 8 Key themes within alternatives proposed

8.1 Section 8 'CUSC Modification[8]' details the Modification process. A Workgroup Consultation Alternative Request can be raised by any CUSC Party, BSC Party, the Citizens Advice or the Citizens Advice Scotland. In the instance that a Workgroup Consultation Alternative Request has been received by a party not listed or by a Workgroup member the Workgroup will 'adopt' the alternative request to include in any potential WACMs.

8.2 Tata Chemicals Europe Ltd did submit an alternative request that was taken forward in the WACM voting by the Workgroup member from the Association for Decentralised Energy (the ADE).

8.3 As part of the Workgroup meeting process and Workgroup Consultation responses the total number of alternatives that the Workgroup discussed as alternative methods to resolve the defects identified under CMP264 and CMP265 were:

- CMP264: **53** (including the original Proposal)
- CMP265: **36** (including the original Proposal).

Of these 89 different options, 62 covered both alternatives to CMP264 and CMP265.

8.4 The Workgroup discussed these potential proposals with a view to narrowing them down into formal alternative proposals. It was decided that the best way to structure the alternative proposals was to replace the current net charging of demand TNUoS with a structure whereby demand was charged on a gross basis (i.e. gross imports without Embedded Generation exports being netted from it) and that an alternative explicit embedded benefit tariff would be applied to embedded exports on a gross basis.

8.5 It was agreed that this would take the form of the demand locational tariff[9] (as now) plus a new value to replace the current demand residual. This element of the new tariff was referred to as "X". This is discussed in more detail below

8.6 The following sections details the discussions of the Workgroup on the merits of these alternatives, categorised by attribute type:

**Affected Generator**

8.7 For the purposes of the options, the Affected Generator described the parties to which the new arrangements would apply. For Modification CMP264 the Affected Generator was defined as all those commissioned after 30 June 2017 and for CMP265 the Affected Generator was defined as any Generator that holds a Capacity Market Contract.

**CMP264:** A number of the alternative options proposed mirrored the same date range but some different definitions were proposed that looked to either extend the date to those from 31 October 2018 or include all commissioned after 30/06/19 and multiyear-newbuild CM/CFD contracted after 14/15. Further options were proposed to define the Affected Generator as all commissioned after 30/06/17 excluding 14&15 CM/CFD or all new excluding 14&15 CM/CFD.

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[8] http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/the-cusc/

[9] This would be the negative of the locational tariff so that if the original demand locational tariff resulted in a payment from demand it would result in a payment to exports from generation.

The rationale for extending the definition was to avoid affecting those users that have already made investment decisions based on the current charging arrangements.

However an alternative view was proposed by a number that it should capture all Generators and not just those commissioned after a specific date.

**CMP265:** A number of the options proposed looked to define the definition further to have that the Affected Generator as being classed as a Generator with CM Contract excluding 2014&2015 CM/CFD round. However an alternative view was proposed by a number that it should capture all Generators and not just those that held a CM Contract.
The rationale for extending the definition to exclude 2014&2015 CM/CFD contracts was to prevent changing transmission charging for Generators that had committed to their CM/CFD contract; whilst the rationale for extending which class of Generator would be captured under the definition was to prevent transmission charges discriminating between two classes of Embedded Generators.

**Grandfathered Generator**

8.8 As discussed in section 7, the Workgroup considered grandfathering to mean an arrangement which preserved a higher level of Embedded Benefit compared with those that are not grandfathered Generators. Therefore, Grandfathered Generators were those parties who would presently receive TNUoS triad embedded benefit and were not considered as an Affected Generator. For Modification CMP264 the Grandfathered Generator would be defined as all commissioned before 1 July 2017 whilst CMP265 has the definition as all Generators without a CM Contract. A number of variants were proposed:

**CMP264:** Include all commissioned before 1 November 2018 or all commissioned before 30 June 2019 excluding those with a multi-year new-build CM/CFD contracted after 2014/2015. Further options were proposed to include all commissioned before 1 July 2017 and with a 2014/2015 CM/CFD contract or all existing with those with a 2014/2015 CM/CFD contract. The final option proposed was to include all commissioned before 1 July 2017 and CHP plants.

**CMP265:** A number of the options proposed looked to extend the definition to those Generators without a CM contract and those that hold a CM/CFD contract for 2014/2015. A number looked to restrict it to those with a CM/CFD contract for 2014/2015 OR those with a CM/CFD contract for 2014/2015 until 2033. In contrast a number of options proposed that grandfathering should not be applied to any Generators.

8.9 Some of the Proposers of alternatives considered that grandfathering should be incorporated to protect existing investor commitments that were generally made on the assumption of higher triads and could safe-guard against rising cost of capital that may be borne by consumers. Furthermore without grandfathering this may lead to plant closure and security of supply issues and that the benefit of reduced reinforcement costs at transmission level are more attributable to existing plant than future plant. Offering a grandfathering element for those obligated under the 2014 or 2015 CM would cap Triad payments at existing levels to allow for the process of setting a realistic/practical date for commissioning cut off matching the obligations under the CM.

8.10 For those options that included grandfathering Embedded Generators with existing CM/CfD until 2033, the reason was to avoid stranding assets/investments for a sub set of users who were holders of Capacity Market and Contracts for Difference agreements. In principle it will protect investment decisions made in good faith when the newly formulated Electricity Market Reform (EMR) auctions were run during 2014 and 2015. These auctions are designed to secure capacity to deliver security of supply, affordability, de-carbonisation and to attract new investment and reduce cost of capital.

8.11 It was the view of the proposer of these alternatives that the auctions were intentionally designed to be complementary to other revenue streams available in the electricity market and importantly market participants were encouraged to take account of alternative revenues when placing their bids to fulfil the contracted obligations. Newbuild Distributed generation assets in both the CM and CfD auctions prior to the announcement of further reviews during 2016 by Ofgem are reliant on their investment case to receive Demand TNUoS embedded benefits. These Newbuild capacity obligations are secured for approximately 15 years any failure to meet these obligations would result in significant termination penalties, sterilisation of sites and capacity from entering future auctions and potentially replacement capacity being bought in the T-1 and T-4 auctions at additional expense.

8.12 The various alternatives have been developed to protect these investment decisions for the duration of their EMR obligations to avoid stranding these assets that could place unnecessary additional risks borne by the end consumer. Analysis presented to the Workgroup suggested a potential benefit to the end consumer of up to £1.5bn through the introduction of specific grandfathering to 2033 for this sub set of capacity[10].

**Embedded Generator Tariffs**

8.13 It was understood by Workgroup Members that affected generators and grandfathered generators could be subject to different Embedded Generator TNUoS tariffs. An Embedded Generator tariff would be made up of a locational element (the demand locational tariffs from the TNUoS transport model) and a residual element.

8.14 X' was used by the workgroup as terminology to capture the replacement value for the residual element of an embedded generator's tariff. Different values of 'X' were considered for the two different groups of Embedded Generator.

**Locational Element**

8.15 Both the CMP264 and CMP265 originals and all proposed alternatives included keeping in the locational element.

**Peak vs. year round**

8.16 The Workgroup discussed whether charges should be based on year round or peak. A number of the alternatives proposed to charge the year round locational tariff on a wider charging base as it would be a better reflection of transmission investment than the Triad charging base. The Triad charging base approach, it was argued, overstates the location benefit by giving full credit based on running over just three half hours and that in negative zones the half hourly tariff is unlikely to discourage generation during high demand periods.

8.17 The Workgroup recognised that there may be merit in reviewing this aspect as part of a wider review but that implementation may be too complex to implement in the time allowed by the Authority and the CUSC panel and the narrow scope of the proposer's identified defects.

**Affected Generator value of 'X'**

8.18 Both originals for CMP264 and CMP265 had this value set at £0. A number of the alternatives provided the value of 'X'. The value of 'x'" all use a common approach that the value of the net element of the Demand Residual is reduced to £0. I.e. the Demand Residual becomes 100% gross. This value of 'x' is a new number to represent a new measure of embedded benefit.

[10] Please refer to the presentation from UKPR in section 6.1

Table 7

| Value of 'X' | Description |
|---|---|
| £32.30 in April 2016 prices + RPI | Based on analysis by Cornwall Energy [11]on the avoided costs of transmission |
| £45.33 in April 2016 prices + RPI | Maintain the value of demand residual in 2016/17 to prevent further increases |
| Avoided GSP investment (last estimate £1.62) | Based on a National Grid estimate of the cost of reinforcing a GSP which is avoided by embedded Generators |
| £20.12<br>This comprises of £18.50 in April 2019 prices + RPI and Avoided GSP cost (last estimate £1.62) | Based on estimated cost of transmission reinforcement cost calculated by Cornwall Energy[12] and + Avoided GSP cost which is based on a National Grid estimate of the cost of reinforcing a GSP which is avoided by embedded Generators[13] |
| £34.11 in April 2016 prices + RPI for 1 charging year then £20.12 as calculated above | Four year average of demand residual to 2016/17 which represents the demand residual while recent investment decisions were made; then based on estimated cost of transmission reinforcement cost calculated by Cornwall Energy[14] and + Avoided GSP cost |
| Generation Residual | Gives the same value of residual for Generators connected to the transmission and distribution system |
| £27.17 in April 2013 prices + RPI for 5 charging years then Generation Residual | Based on the level that demand residual was at when this issue was last considered in 2013/4 during an National Grid informal consultation. |
| Generation Residual + Avoided GSP investment (last estimate £1.62) | Gives the same value of residual for Generators connected to the transmission and distribution system and takes account of the avoided cost of reinforcing a GSP as estimate by National Grid |
| Magnitude of Lowest locational value<br>(Locational including both year round and peak security year HH demand TNUoS tariff elements) | Maintains the full cost differential of the indicative locational signal which represents the value of embedded Generators locating within each demand zone |
| Demand residual with offshore | Calculates what the embedded benefit would have been if |

[11] http://www.theade.co.uk/embedded-benefits-review--manufacturing-energy-cost-concerns_4069.html

[12] http://www.theade.co.uk/embedded-benefits-review--manufacturing-energy-cost-concerns_4069.html

[13]See section 4.6 of "Informal Review Paper: Review of the Embedded (Distributed) Generation Benefit arising from transmission charges" http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=29996

[14] http://www.theade.co.uk/embedded-benefits-review--manufacturing-energy-cost-concerns_4069.html

| | |
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| costs removed | the cost of offshore transmission were removed |

**Grandfathered Generator value of 'X'**

8.19 Both originals for CMP264 and CMP265 had this value set to the existing net charge. A number of the alternatives agreed that this value should be net. Other alternatives had that the value was not applicable or provided a value and timeframe for application.

Table 8

| Grandfathered Generator value of 'X' | Description |
|---|---|
| £34.11 in April 2016 prices + RPI for 10 years then move to Affected Generator | Four year average of demand residual to 2016/17 which represents the demand residual while recent investment decisions were made |
| £45.33 in April of first applicable charging year of implementation + RPI | Maintain the value of demand residual from 2016/17 to prevent further increases. The hard coded value will be increased by RPI only after the WACM has been implemented |
| £45.33 | Maintain the value of demand residual in 2016/17 to prevent further increases |
| £45.33 in April 2016 prices + RPI | Maintain the value of demand residual in 2016/17 to prevent further increases |

**Flooring to £zero**

8.20 **CMP264** original and all but one of the alternatives proposed that the total tariff applicable to affected and grandfathered Embedded exports should be floored to £zero because of the view that a negative Triad benefit may provide an incentive for Embedded Generators to turn down to avoid generating during Triad periods. The rationale was that this approach of flooring at £zero would avoid the potential distortionary incentive some Workgroup members considered exists because of the non-cost reflective nature of using the Triad as the charging base for this benefit (i.e. effectively applying a negative Year Round tariff to a measure of peak generation). Furthermore there was a view that this may no longer be required if a different definition of charging periods (e.g. different to Triad) were introduced.

8.21 This approach was shared by all of the potential alternatives proposed except for one option that proposed that there shouldn't be a floor of £zero included. The rationale for this one option was that the proposer of this option considered it was a better reflection of transmission investment and that in negative zones the half hourly tariff is unlikely to discourage generation during high demand periods as the alternative used a longer time window instead of the Triads currently used. The Workgroup discussed how it could distort dispatch and how this may worsen the situation if over a longer period than the Triad. As the alternative was not progressed as a WACM the Workgroup did not consider this issue further.

8.22 For **CMP265** the majority of alternatives had that there should be a floor of £0, the only ones that considered that there shouldn't be a floor of £zero were the original and one of the alternatives (the same proposer as the one for CMP264 that didn't have flooring to £zero). The rationale was as above and also that the proposer of the original did not consider the rationale for flooring to £zero as the locational charge and how it is applied, is supposed to be cost-reflective. If it was considered not to be cost reflective then it should be amended, via a separate change, to become cost-reflective.

**3 year phasing**

8.23 Both the CMP264 and CMP265 originals did not include a concept of phasing. Whilst the majority of alternatives also did not include the concept of phasing a number of alternates did on the basis that it would stop there being undue disruption to the market. It would limit the impact of a significant change in the tariffs for Embedded Generators and allow National Grid time to understand the implications from a forecasting tariffs perspective. Whilst a number of the Workgroup acknowledged that this approach may reduce the concerns of the 'cliff edge', there was a view that by phasing all that will happen is that industry will delay the 'cliff edge'.

**Charging Window – applicable to affected Generator and Grandfathered Generator**

8.24 The majority of alternates and the originals had that this should be against Triad. Different Charging Windows were suggested ranging from using 16:00 to 19:00 weekdays November to February or 16:30 to 19:30 weekdays November to January and 17:00 to 20:00 February through to extending the Charging Window out to 16:00 to 19:00 year round.

8.25 Amending the Charging Window for all demand users of the system was discounted as it was considered out of scope of the defect of the Modifications.

**Mixed sites**

8.26 Whilst the Workgroup discussed whether there should be a separate feature for mixed sites it was agreed that any Affected Generator or Grandfathered Generator that held mixed sites meters would be captured under the definitions.

**Provision of data**

8.27 It was raised by a number of Workgroup members concerns about using existing BSC Systems data flows and impacts of changing older systems and that dependant on the change new systems may need to be developed. As a result proposals had their dates moved forward, but the Workgroup noted that the governance of BSC systems is under the BSC and implementation may take longer were new systems to be required.

**Renewable Obligations (RO)**

8.28 A Workgroup member suggested that where the scope of grandfathered generator includes CfDs contracts that this should be extended to RO. However it was recognised that with the closure date of the Renewable Obligation and the implementation dates proposed, it was thought unlikely that any of the proposals with a cut-off date would impact RO plant as they should have all commissioned prior to that date.

# 9 Details of Workgroup Alternative CUSC Modifications (WACMs)

9.1 The Workgroup voted on the 19 September on which potential alternatives should become Workgroup Alternative CUSC Modifications (WACMs). This resulted in:

- CMP264: **8** alternatives being voted by majority as WACMs
- CMP265: **4** alternatives being voted by majority as WACMs

9.2 During the voting exercise a seven of the alternatives proposed as WACMs were withdrawn by Workgroup members.

9.3 Following the voting by Workgroup Members, the **Chair** exercised the option to retain an additional **29** of the different alternatives that did not receive a majority vote as these are considered by the Chair to be better than the baseline and facilitates the CUSC charging objective (a) of "That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity".

9.4 In addition the Chair considered that the requirement to save these additional WACMs reflected the composition of the Workgroup and the variety of views.

9.5 The breakdown of WACMs retained was:

- CMP264: **15** alternatives being voted in by the Workgroup Chair as a WACM
- CMP265: **14** alternatives being voted in by the Workgroup Chair as a WACM

9.6 Tables 9 and 10 detail the elements in each WACM and the original Proposals for CMP264 and CMP265.

9.7 More detail on the rationale for the value of 'X' can be found in paragraph 8.18 and 8.19

Table 9 – elements for CMP264 (WACM and original)

| WACM No | WACM Proposer | Affected Generator (AG) | Grandfathered Generator (GG) | Affected Generator Value of 'X' | Grandfathered Generator Value of 'X' | Preferred First Charging Year (where specified) | Floored at £0 (Y/N) | 3 Year Phasing | Charging Window Applicable to AG & GG |
|---|---|---|---|---|---|---|---|---|---|
| n/a | CMP264 Original – SP | All commissioned after 30/06/17 | All commissioned before 01/07/17 | £0 | Net | | Y | N | Triad |
| WACM 1 | Centrica B (CMP264) | All | N/A | Generation Residual | N/A | 2020/2021 | Y | N | Triad |
| WACM 2 | NG C (CMP264) | All | N/A | Generation Residual | N/A | | Y | Y | Triad |
| WACM 3 | Uniper A (CMP264) | All | N/A | Avoided GSP investment (last estimate £1.62) | N/A | 2018/19 | Y | N | Triad |
| WACM 4 | SSE A (CMP264) | All | N/A | Avoided GSP investment (last estimate £1.62) | N/A | | Y | Y | Triad |
| WACM 5 | SSE B (CMP264) | All | N/A | Generation Residual + Avoided GSP investment (last estimate £1.62) | N/A | | Y | Y | Triad |
| WACM 6 | NG A (CMP264) | All | N/A | Magnitude of Lowest | N/A | 2018/19 | Y | N | Triad |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | locational value | | | | | |
| **WACM No** | **WACM Proposer** | **Affected Generator (AG)** | **Grandfathered Generator (GG)** | **Affected Generator Value of 'X'** | **Grandfathered Generator Value of 'X'** | **Preferred First Charging Year (where specified)** | **Floored at £0 (Y/N)** | **3 Year Phasing** | **Charging Window Applicable to AG & GG** |
| WACM 7 | NG D (CMP264) | All | N/A | Magnitude of Lowest locational value | N/A | 2018/19 | Y | Y | Triad |
| WACM 8 | ADE E (CMP264) | All | N/A | £32.30 in April 2016 prices + RPI | N/A | | Y | N | Triad |
| WACM 9 | Infinis A (CMP264) | All | N/A | £34.11 for 1 year then £20.12 | N/A | | Y | N | Triad |
| WACM 10 | Greenfrog A (CMP264) | All | N/A | £45.33 in April 2016 prices + RPI | N/A | | Y | N | Triad |
| WACM 11 | Eider A (CMP264) | All | N/A | Demand residual with offshore costs removed | N/A | 2018/19 | Y | N | Triad |
| WACM 12 | UKPR F1 (CMP264) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Generation Residual | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 13 | UKPR G1 (CMP264) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all | Avoided GSP investment (last estimate £1.62) | £45.33 in April of first applicable charging year of implementation + | | Y | N | Triad |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | CFD contracts from 14&15 | | RPI | | | | |
| **WACM No** | **WACM Proposer** | **Affected Generator (AG)** | **Grandfathered Generator (GG)** | **Affected Generator Value of 'X'** | **Grandfathered Generator Value of 'X'** | **Preferred First Charging Year (where specified)** | **Floored at £0 (Y/N)** | **3 Year Phasing** | **Charging Window Applicable to AG & GG** |
| WACM 14 | UKPR H1 (CMP264) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Generation Residual + Avoided GSP investment (last estimate £1.62) | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 15 | UKPR I1 (CMP264) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Magnitude of lowest locational value | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 16 | UKPR J1 (CMP264) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | £20.12 + RPI | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 17 | UKPR K1 (CMP264) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts | £32.30 in April 2016 prices + RPI | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | from 14&15 | | | | | | |
| **WACM No** | **WACM Proposer** | **Affected Generator (AG)** | **Grandfathered Generator (GG)** | **Affected Generator Value of 'X'** | **Grandfathered Generator Value of 'X'** | **Preferred First Charging Year (where specified)** | **Floored at £0 (Y/N)** | **3 Year Phasing** | **Charging Window Applicable to AG & GG** |
| WACM 18 | UKPR L1 (CMP264) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Demand residual with offshore costs removed | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 19 | SP B | All commissioned after 30/06/17 | All commissioned before 01/07/17 | £0 | £45.33 in April 2016 prices + RPI | | Y | N | Triad |
| WACM 20 | Alkane A | All commissioned after 31/10/18 | All commissioned before 01/11/18 | £27.70 for 5 charging years then Generation Residual | £45.33 in April 2016 prices + RPI until 31/03/33 then move to AG | 2018/19 | Y | N | Triad |
| WACM 21 | Alkane B | All commissioned after 31/10/18 | All commissioned before 01/11/18 | Magnitude of lowest locational value | £45.33 in April 2016 prices + RPI until 31/03/33 then move to AG | | Y | N | Triad |
| WACM 22 | ADE C | All commissioned after 30/06/19 and multiyear-newbuild CM/CFD contracted after | All commissioned before 30/06/19 excluding multiyear- | £0 | £45.33 in April 2016 prices + RPI | | Y | N | Triad |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 14/15 | newbuild CM/CFD contracted after 14/15 | | | | | | |
| **WACM No** | **WACM Proposer** | **Affected Generator (AG)** | **Grandfathered Generator (GG)** | **Affected Generator Value of 'X'** | **Grandfathered Generator Value of 'X'** | **Preferred First Charging Year (where specified)** | **Floored at £0 (Y/N)** | **3 Year Phasing** | **Charging Window Applicable to AG & GG** |
| WACM 23 | Infinis B | All excluding grandfathered generators | All commissioned before 01/07/17 and multi-year, new build 14&15 CM/CFD | £34.11 + RPI for 1 charging year then £20.12 +RPI on-going | £34.11 in April 2016 prices + RPI for 10 years then move to AG | | Y | N | Triad |

Table 10 elements for CMP265 (WACM and original)

| WACM No | WACM Proposer | Affected Generator (AG) | Grandfathered Generator (GG) | Affected Generator Value of 'X' | Grandfathered Generator Value of 'X' | Preferred First Charging Year (where specified) | Floored at £0 (Y/N) | 3 Year Phasing | Charging Window Applicable to AG & GG |
|---|---|---|---|---|---|---|---|---|---|
| n/a | CMP265 Original - EDF A | Generator with CM Contract | Generator without CM Contract | £0 | Net | | N | N | Triad |
| WACM 1 | Centrica B (CMP265) | All | N/A | Generation Residual | N/A | 2020/2021 | Y | N | Triad |

| WACM No | WACM Proposer | Affected Generator (AG) | Grandfathered Generator (GG) | Affected Generator Value of 'X' | Grandfathered Generator Value of 'X' | Preferred First Charging Year (where specified) | Floored at £0 (Y/N) | 3 Year Phasing | Charging Window Applicable to AG & GG |
|---|---|---|---|---|---|---|---|---|---|
| WACM 2 | NG C (CMP265) | All | N/A | Generation Residual | N/A | | Y | Y | Triad |
| WACM No | WACM Proposer | Affected Generator (AG) | Grandfathered Generator (GG) | Affected Generator Value of 'X' | Grandfathered Generator Value of 'X' | Preferred First Charging Year (where specified) | Floored at £0 (Y/N) | 3 Year Phasing | Charging Window Applicable to AG & GG |
| WACM 3 | Uniper A (CMP265) | All | N/A | Avoided GSP investment (last estimate £1.62) | N/A | 2018/19 | Y | N | Triad |
| WACM 4 | SSE A (CMP265) | All | N/A | Avoided GSP investment (last estimate £1.62) | N/A | | Y | Y | Triad |
| WACM 5 | SSE B (CMP265) | All | N/A | Generation Residual + Avoided GSP investment (last estimate £1.62) | N/A | | Y | Y | Triad |
| WACM 6 | NG A (CMP265) | All | N/A | Magnitude of Lowest locational value | N/A | 2018/19 | Y | N | Triad |

| WACM No | WACM Proposer | Affected Generator (AG) | Grandfathered Generator (GG) | Affected Generator Value of 'X' | Grandfathered Generator Value of 'X' | Preferred First Charging Year (where specified) | Floored at £0 (Y/N) | 3 Year Phasing | Charging Window Applicable to AG & GG |
|---|---|---|---|---|---|---|---|---|---|
| WACM 7 | NG D (CMP265) | All | N/A | Magnitude of Lowest locational value | N/A | 2018/19 | Y | Y | Triad |
| WACM 8 | ADE E (CMP265) | All | N/A | £32.30 in April 2016 prices + RPI | N/A | | Y | N | Triad |
| WACM 9 | Infinis A (CMP265) | All | N/A | £34.11 for 1 year then £20.12 | N/A | | Y | N | Triad |
| WACM 10 | Greenfrog A (CMP265) | All | N/A | £45.33 in April 2016 prices + RPI | N/A | | Y | N | Triad |
| WACM 11 | Eider A (CMP265) | All | N/A | Demand residual with offshore costs removed | N/A | 2018/19 | Y | N | Triad |
| WACM 12 | UKPR F1 (CMP265) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Generation Residual | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |

| WACM No | WACM Proposer | Affected Generator (AG) | Grandfathered Generator (GG) | Affected Generator Value of 'X' | Grandfathered Generator Value of 'X' | Preferred First Charging Year (where specified) | Floored at £0 (Y/N) | 3 Year Phasing | Charging Window Applicable to AG & GG |
|---|---|---|---|---|---|---|---|---|---|
| WACM 13 | UKPR G1 (CMP265) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Avoided GSP investment (last estimate £1.62) | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 14 | UKPR H1 (CMP265) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Generation Residual + Avoided GSP investment (last estimate £1.62) | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 15 | UKPR I1 (CMP265) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Magnitude of lowest locational value | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |

| WACM No | WACM Proposer | Affected Generator (AG) | Grandfathered Generator (GG) | Affected Generator Value of 'X' | Grandfathered Generator Value of 'X' | Preferred First Charging Year (where specified) | Floored at £0 (Y/N) | 3 Year Phasing | Charging Window Applicable to AG & GG |
|---|---|---|---|---|---|---|---|---|---|
| WACM 16 | UKPR J1 (CMP265) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | £20.12 + RPI | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 17 | UKPR K1 (CMP265) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | £32.30 in April 2016 prices + RPI | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |
| WACM 18 | UKPR L1 (CMP265) | All excluding grandfathered generators | Multi-year 14&15 CM contracts for new build generation & all CFD contracts from 14&15 | Demand residual with offshore costs removed | £45.33 in April of first applicable charging year of implementation + RPI | | Y | N | Triad |

9.8 Both originals and all approved WACMs require changes to existing metering data flows and demand forecasts to support TNUoS charging. The changes to the metering data flows will be specified under BSC Modifications P348 and P349. The changes to demand forecast are specified in the legal text changes for CMP264 and CMP265. This can be found in Annex 4 of this report.

## 10 The approach to determining the legal text changes

10.1 It was agreed by the Workgroup that a sub-group should be formed to consider the legal text changes to Section 14 the CUSC. This group convened five times. Annex 4 details the changes to the CUSC should either an original or a WACM be approved by the Authority for implementation.

10.2 The legal text sub-group considered how best to facilitate the drafting of a large number of WACMs and agreed a modular approach that was in line with the formation of proposals in the main sub group. This approach used one set of changes that took the majority of changes to CUSC into account but was combined with 'bolt on' definitions that would be inserted depending on which original or alternative modification was in question.

10.3 Central to this approach was using the terms Affected Export and Grandfathered Export. These terms are used to refer to users that export onto the distribution system and depending on the particular proposal, would be treated differently to today. For CMP264 and CMP265 originals, grandfathered exports continue to be treated on a net basis as today.

10.4 There are two main approaches for defining the difference between grandfathered and affected exports; these were:

- If the generator held a capacity market (CM) obligation or contract for difference (CFD)
- The commissioning date of the generator according to its G59 certification

10.5 The sub-group discussed what should happen if a CM obligation or CFD were terminated. The group concluded that the generator should be treated as not having a CM obligation or CFD from the beginning of the following charging year.

10.6 The scenario of secondary trading of a CM obligation was raised where one party may have been awarded the obligation at auction but the obligation is then passed the obligation to a third party. The approach for CMP265 original is to define affected embedded exports as generation that holds a CM obligation from either auction or secondary trading. All other proposals that used CM obligations as a differentiator between affected and grandfathered exports do not consider secondary trading; they only define generators according to CM obligations that were awarded at auction.

10.7 The sub-group considered how best to capture the commissioning date of an Embedded Generator and at decided that the use of G59 certification is the most appropriate method. The G59 certificate is a document that is signed by a DNO for any generation connecting that is greater than 3.68kW. While this approach was agreed by the group there were a number of limitations to this method highlighted by sub-group members. These included:

- The G59 certification has a de-minimis level of 3.68kW which will mean that some generators are not captured
- There is a possibility that a DNO may issue a new G59 certificate for reasons other than the replacement or addition of existing generation. The effect of this would be that exports would move from grandfathered to affected exports as a result which is not the intended effect of using G59 certification.
- Concerns were raised that certification could be awarded to generation and dated in relation to the equipment meeting certain standards and not the commissioning of the equipment. The intention of using the G59 certification is only to identify the commissioning date of the generation and not dates of meeting standards unrelated to commissioning.

- There is currently a possibility that G59 certification will be replaced by a new certificate. It was agreed that if this does happen, the appropriate replacement will be adopted as the method of determining commissioning date.

10.8 As CMP264 and CMP265 have been raised as changes to the Charging Methodology of the CUSC and that there may be a need to amend other sections of the CUSC that do not relate to Section 14. Consequential Modifications CMP269 and CMP270 have been raised to detail the potential changes to Section 3 and Section 11 of the CUSC.

10.9 It is suggested that these Modifications are considered together with CMP264 and CMP265 to cover changes to Section 3 and Section 11. Following the legal text sub group meetings it was confirmed that only changes to Section 11 would be required:

- Section 11: the proposals will require new definitions such as New Embedded Generation (i.e. those who qualify for a different value of embedded benefit under the CMP264 Original) [Capacity Market Embedded Generation (i.e. those who embedded generators who hold a capacity market agreement)] in order for these terms to be in Section 14 and Section 11 of the CUSC consistently.

## 11 Workgroup voting

11.1 The Workgroup met on 5 October and voted on the Original Proposals and the Workgroup Alternative CUSC Modifications. The voting was comprised of the rounds of voting for each Modification.

**Vote 1: Does the original or a WACM facilitate the objectives better than the baseline?**

11.2 For **CMP264/CMP269** ***WACM11*** received the highest number of votes for vote 1. The votes received are as follows:

Table 11

CMP264/CMP269 Vote 1 Record

| WACM Ref | WACM identifier | Workgroup voted yes overall |
|---|---|---|
| Original | CMP264/CMP269 | 5 |
| WACM 1 | Centrica B (CMP264) | 8 |
| WACM 2 | NG C (CMP264) | 6 |
| WACM 3 | Uniper A (CMP264) | 7 |
| WACM 4 | SSE A (CMP264) | 5 |
| WACM 5 | SSE B (CMP264) | 6 |
| WACM 6 | NG A (CMP264) | 5 |
| WACM 7 | NG D (CMP264) | 5 |
| WACM 8 | ADE E (CMP264) | 6 |
| WACM 9 | Infinis A (CMP264) | 6 |
| WACM 10 | Greenfrog A (CMP264) | 8 |
| WACM 11 | Eider A (CMP264) | 9 |
| WACM 12 | UKPR F1 (CMP264) | 2 |
| WACM 13 | UKPR G1 (CMP264) | 2 |
| WACM 14 | UKPR H1 (CMP264) | 3 |
| WACM 15 | UKPR I1 (CMP264) | 4 |
| WACM 16 | UKPR J1 (CMP264) | 6 |
| WACM 17 | UKPR K1 (CMP264) | 6 |
| WACM 18 | UKPR L1 (CMP264) | 7 |
| WACM 19 | SP B | 4 |

| | | |
|---|---|---|
| WACM 20 | Alkane A | 7 |
| WACM 21 | Alkane B | 6 |
| WACM 22 | ADE C | 5 |
| WACM 23 | Infinis B | 6 |

11.3 For **CMP265/CMP270** a number of the WACMs received the equal highest number of votes for vote 1. The votes received are as follows:

Table 12

CMP265/CMP270 Vote 1 Record

| WACM Ref | WACM identifier | Workgroup voted yes overall |
|---|---|---|
| Original | CMP265/CMP270 | 5 |
| WACM 1 | Centrica B (CMP264) | 6 |
| WACM 2 | NG C (CMP264) | 5 |
| WACM 3 | Uniper A (CMP264) | 6 |
| WACM 4 | SSE A (CMP264) | 5 |
| WACM 5 | SSE B (CMP264) | 5 |
| WACM 6 | NG A (CMP264) | 6 |
| WACM 7 | NG D (CMP264) | 6 |
| WACM 8 | ADE E (CMP264) | 7 |
| WACM 9 | Infinis A (CMP264) | 7 |
| WACM 10 | Greenfrog A (CMP264) | 7 |
| WACM 11 | Eider A (CMP264) | 7 |
| WACM 12 | UKPR F1 (CMP264) | 1 |
| WACM 13 | UKPR G1 (CMP264) | 1 |
| WACM 14 | UKPR H1 (CMP264) | 2 |
| WACM 15 | UKPR I1 (CMP264) | 3 |
| WACM 16 | UKPR J1 (CMP264) | 5 |
| WACM 17 | UKPR K1 (CMP264) | 5 |
| WACM 18 | UKPR L1 (CMP264) | 6 |

**Vote 2: Does the WACM facilitate the objectives better than the Original?**

11.4 For **CMP264/CMP269** a number of the WACMs received the equal highest number of votes for vote 2. The votes received are as follows:

Table 13

CMP264/CMP269 Vote 2 Record

| WACM Ref | WACM identifier | Workgroup voted yes overall |
|---|---|---|
| WACM 1 | Centrica B (CMP264) | 10 |
| WACM 2 | NG C (CMP264) | 8 |
| WACM 3 | Uniper A (CMP264) | 10 |
| WACM 4 | SSE A (CMP264) | 7 |
| WACM 5 | SSE B (CMP264) | 7 |
| WACM 6 | NG A (CMP264) | 9 |
| WACM 7 | NG D (CMP264) | 8 |
| WACM 8 | ADE E (CMP264) | 9 |
| WACM 9 | Infinis A (CMP264) | 8 |
| WACM 10 | Greenfrog A (CMP264) | 9 |
| WACM 11 | Eider A (CMP264) | 10 |
| WACM 12 | UKPR F1 (CMP264) | 4 |
| WACM 13 | UKPR G1 (CMP264) | 4 |
| WACM 14 | UKPR H1 (CMP264) | 4 |
| WACM 15 | UKPR I1 (CMP264) | 5 |
| WACM 16 | UKPR J1 (CMP264) | 5 |
| WACM 17 | UKPR K1 (CMP264) | 6 |
| WACM 18 | UKPR L1 (CMP264) | 6 |
| WACM 19 | SP B | 9 |
| WACM 20 | Alkane A | 9 |
| WACM 21 | Alkane B | 8 |
| WACM 22 | ADE C | 7 |
| WACM 23 | Infinis B | 6 |

11.5 For **CMP265/CMP270** ***WACM11*** received the highest number of votes for vote 1. The votes received are as follows:

Table 14

CMP265/CMP270 Vote 2 Record

| WACM Ref | WACM identifier | Workgroup voted yes overall |
|---|---|---|
| WACM 1 | Centrica B (CMP264) | 9 |
| WACM 2 | NG C (CMP264) | 9 |
| WACM 3 | Uniper A (CMP264) | 9 |

| | | |
|---|---|---|
| WACM 4 | SSE A (CMP264) | 8 |
| WACM 5 | SSE B (CMP264) | 8 |
| WACM 6 | NG A (CMP264) | 8 |
| WACM 7 | NG D (CMP264) | 8 |
| WACM 8 | ADE E (CMP264) | 8 |
| WACM 9 | Infinis A (CMP264) | 7 |
| WACM 10 | Greenfrog A (CMP264) | 10 |
| WACM 11 | Eider A (CMP264) | 11 |
| WACM 12 | UKPR F1 (CMP264) | 4 |
| WACM 13 | UKPR G1 (CMP264) | 4 |
| WACM 14 | UKPR H1 (CMP264) | 4 |
| WACM 15 | UKPR I1 (CMP264) | 5 |
| WACM 16 | UKPR J1 (CMP264) | 5 |
| WACM 17 | UKPR K1 (CMP264) | 5 |
| WACM 18 | UKPR L1 (CMP264) | 6 |

**Vote 3: Which option is considered to be the best?**

11.6 For **CMP264/CMP269** ***WACM3*** received the highest number of votes for vote 3 (with **four of the 22** Workgroup members voting that as the best option). The next highest options voted for was the baseline and WACM 8 with three votes each. The votes received are as follows:

Table 15

CMP264/CMP269 Vote 3 Record

| WACM Ref | WACM identifier | Workgroup members voted as BEST |
|---|---|---|
| | Original Proposal | 0 |
| WACM 1 | Centrica B (CMP264) | 1 |
| WACM 2 | NG C (CMP264) | 0 |
| WACM 3 | Uniper A (CMP264) | 4 |
| WACM 4 | SSE A (CMP264) | 0 |
| WACM 5 | SSE B (CMP264) | 1 |
| WACM 6 | NG A (CMP264) | 1 |
| WACM 7 | NG D (CMP264) | 0 |

| | | |
|---|---|---|
| WACM 8 | ADE E (CMP264) | 3 |
| WACM 9 | Infinis A (CMP264) | 1 |
| WACM 10 | Greenfrog A (CMP264) | 2 |
| WACM 11 | Eider A (CMP264) | 1 |
| WACM 12 | UKPR F1 (CMP264) | 0 |
| WACM 13 | UKPR G1 (CMP264) | 0 |
| WACM 14 | UKPR H1 (CMP264) | 0 |
| WACM 15 | UKPR I1 (CMP264) | 1 |
| WACM 16 | UKPR J1 (CMP264) | 0 |
| WACM 17 | UKPR K1 (CMP264) | 0 |
| WACM 18 | UKPR L1 (CMP264) | 0 |
| WACM 19 | SP B | 2 |
| WACM 20 | Alkane A | |
| WACM 21 | Alkane B | 1 |
| WACM 22 | ADE C | |
| WACM 23 | Infinis B | |
| Baseline | | 3 |
| Abstained | | 1 |

11.7 For **CMP265/CMP270** ***WACM10*** received the highest number of votes with **four of the 22** Workgroup members voting that as the best option. The next highest options voted for was the baseline, WACM 3 and WACM 8 with three votes each. The votes received are as follows:

CMP265/CMP270 Vote 3 Record

Table 16

| WACM Ref | WACM identifier | Workgroup members voted as BEST |
|---|---|---|
| | Original Proposal | 1 |
| WACM 1 | Centrica B (CMP265) | 1 |
| WACM 2 | NG C (CMP265) | 0 |
| WACM 3 | Uniper A (CMP265) | 3 |
| WACM 4 | SSE A (CMP265) | 1 |
| WACM 5 | SSE B (CMP265) | 1 |
| WACM 6 | NG A (CMP265) | 1 |
| WACM 7 | NG D (CMP265) | 0 |
| WACM 8 | ADE E (CMP265) | 3 |

| | | |
|---|---|---|
| WACM 9 | Infinis A (CMP265) | 1 |
| WACM 10 | Greenfrog A (CMP265) | 4 |
| WACM 11 | Eider A (CMP265) | 1 |
| WACM 12 | UKPR F1 (CMP265) | 0 |
| WACM 13 | UKPR G1 (CMP265) | 0 |
| WACM 14 | UKPR H1 (CMP265) | 0 |
| WACM 15 | UKPR I1 (CMP265) | 1 |
| WACM 16 | UKPR J1 (CMP265) | 0 |
| WACM 17 | UKPR K1 (CMP265) | 0 |
| WACM 18 | UKPR L1 (CMP265) | 0 |
| Baseline | | 3 |
| Abstention | | 1 |

11.8 With respect to CMP269 & CMP270 the Workgroup discussed as part of their voting how these two modifications are in essence required for the implementation of CMP264 and 265. A view was expressed that the existing governance arrangements which allow for Modifications to be assessed against different applicable CUSC objectives in itself was inefficient. Arguably implementation of any of the original or WACMs under CMP264 and CMP265 cannot be said to be efficient without the corresponding WACM from CMP269 and CMP270. These modifications could therefore be said to better meet applicable objective (d) (where the corresponding modification has been implemented) regardless of their impact on applicable objectives (a)-(c).

11.9 Below details the rationale for vote 3 for each voting Workgroup member. The complete record of voting for each Workgroup member for each vote is contained in Volume 4 of this report.

Table 17

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| James Anderson | WACM 19 | WACM19 best meets the defect identified in CMP264 in that it ensures that future Capacity Mechanism auctions will be based on a level playing field and that embedded generation participants will not take account of non cost-reflective Triad avoidance payments in making their bids. Capping the Triad avoidance payment at the 2016/17 level ensures that the detriment to consumers does not increase while an enduring solution to identifying a cost-reflective payment for embedded generation is developed. | | WACM 4 | WACM4 applies to all embedded generators thus avoiding any discrimination between different classes. It removes a non cost-reflective payment from embedded generation thus improving competition between embedded and transmission connected generation. thus better facilitating Applicable Charging Objective (b).<br>Removing a non cost reflective Triad avoidance payment, retaining the cost-reflective locational signal (floored at zero) and introducing a payment which reflects the avoided cost of transmission investment will best facilitate Applicable Charging Objective (b). | |
| Tim Collins | WACM 1 | Performs best against the relevant objectives. Broadly creates equivalence in TNUoS charging between new DG, existing DG and TG so significant benefits to cost reflectivity and effective competition. Preferred implementation date of April 2020 respects the CM price commitment cycle. Relatively simple to implement compared with other WACMs and decent lead time allowed for system/process changes. | Broadly creates equivalence in TNUoS charging between new DG, existing DG and TG so significant benefits to cost reflectivity and effective competition. Preferred implementation date of April 2020 respects the CM price commitment cycle. Relatively simple to implement compared with other WACMs and decent lead time allowed for system/process changes. | WACM 1 | Performs best against the relevant objectives. Broadly creates equivalence in TNUoS charging between new DG, existing DG and TG so significant benefits to cost reflectivity and effective competition. Avoids linking EG TNUoS to the Capacity Market, which is arbitrary and unnecessary. Preferred implementation date of April 2020 respects the CM price commitment cycle. Relatively simple to implement compared with other WACMs and decent lead time allowed for system/process changes. | |
| Mike Davies | WACM 11 | This option has a logical derivation of the costs used to assess the | | WACM 11 | This option has a logical derivation of the costs used to | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | embedded benefit. New investment in the transmission system largely to support new renewables should be ring-fenced and taken out of the calculation of TNUoS. It is simpler than other proposals to implement and able to be implemented much earlier, particularly in its original form. It allows for further refinement as more costs can be identified and excluded that are associated with technologies where state aid is supporting them. It addresses a major driver of increasing levels of embedded benefit but does not create major changes which may undermine investor confidence in the market or lead to the closure of large volumes of embedded generation, threatening energy security and increasing energy costs for consumers. Finally it preserves a structure of embedded benefits which has been reviewed on many occasions by Ofgem over a period of more than twenty years and found to be robust and fit for purpose. Through a modest change this key embedded benefit structure is made more fit for purpose.. The original form of this proposal was non-discriminatory between *behind the meter* and *in front of the meter* embedded generation and DSR. Whereas today, these parties are treated equally, the ToR of the Working Group prescribed discriminatory proposals for change. | | | assess the embedded benefit. New investment in the transmission system largely to support new renewables should be ring-fenced and taken out of the calculation of TNUoS. It is simpler than other proposals to implement and able to be implemented much earlier, particularly in its original form. It allows for further refinement as more costs can be identified and excluded that are associated with technologies where state aid is supporting them. It addresses a major driver of increasing levels of embedded benefit but does not create major changes which may undermine investor confidence in the market or lead to the closure of large volumes of embedded generation, threatening energy security and increasing energy costs for consumers. Finally it preserves a structure of embedded benefits which has been reviewed on many occasions by Ofgem over a period of more than twenty years and found to be robust and fit for purpose. Through a modest change this key embedded benefit structure is made more fit for purpose.. The original form of this proposal was non-discriminatory between *behind the meter* and *in front of the meter* embedded generation and DSR. Whereas today, these parties are treated equally, the ToR of the Working Group prescribed discriminatory proposals for change. | |
| Stephen Davies * (Laurence | WACM 8 | Continues to treat all embedded generation in a non-discriminatory way allowing effective competition and minimising the additional administrative burden. Whilst not based upon a comprehensive review | | WACM 8 | Continues to treat all embedded generation in a non-discriminatory way allowing effective competition and minimising the additional administrative burden. Whilst | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| Barrett) | | which we believe would be the best approach, it is based upon analysis which presents a logical case for the proposed value being more cost-reflective and hence it is likely to improve cost reflectivity from the currently spiralling baseline. | | | not based upon a comprehensive review which we believe would be the best approach, it is based upon analysis which presents a logical case for the proposed value being more cost-reflective and hence it is likely to improve cost reflectivity from the currently spiralling baseline. | |
| Fruzina Kemenes | CUSC Baseline | We would like to highlight the overarching concern that the working group have not had the opportunity to conduct sufficient analysis or evaluate the workings or impacts of any of the proposals. As such voting for any option being better than the baseline is irresponsible and not evidence based. The accelerated timetable and volume of WACMs has been a barrier to informed voting.<br>The reasons for rejecting all the individual options are detailed above.<br>To summarise, the proposals suffer from different variants of the issues listed below:<br>A) Proposals introduce undue discrimination between users that have the same network impact. (Behind the meter and directly connected embedded generation, new/old/CM/non-CM)<br><br>Proposals therefore risk distortion of competition.<br><br>Where gross charging is applied to all embedded generation the potential risks of distorting competition now in favour of transmission connected generators has not been examined.<br><br>B) Treating customers with the same network impact in different ways can never be cost reflective (or an improvement on cost reflectivity). | | CUSC Baseline | We would like to highlight the overarching concern that the working group have not had the opportunity to conduct sufficient analysis or evaluate the workings or impacts of any of the proposals. As such voting for any option being better than the baseline is irresponsible and not evidence based. The accelerated timetable and volume of WACMs has been a barrier to informed voting.<br>The reasons for rejecting all the individual options are detailed above.<br>To summarise, the proposals suffer from different variants of the issues listed below:<br>A) Proposals introduce undue discrimination between users that have the same network impact. (Behind the meter and directly connected embedded generation, new/old/CM/non-CM)<br><br>Proposals therefore risk distortion of competition.<br><br>Where gross charging is applied to all | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | While identifying issues with cost reflectivity of current charges the issue remains unresolved by all proposals.<br><br>Some proposals attempt to freeze net charging levels at a value that is designed by the proposers to be cost reflective. While these are pragmatic approaches for a 'stop-gap' solution - the workgroup has not analysed the basis of the values selected for the frozen tariffs.<br><br>Some base their proposals on locational signal remaining intact: this does not produce a cost reflective signal as retained locational signals are not reflective of SQSS. Flooring locational signal also produces a further distorted locational signal.<br><br>E) All proposals have a higher admin burden than the baseline due to level of work to support ring fencing of specified customers and application of different sets of tariffs. Change of supplier process and additional flows / central data store required. | | | embedded generation the potential risks of distorting competition now in favour of transmission connected generators has not been examined.<br><br>B) Treating customers with the same network impact in different ways can never be cost reflective (or an improvement on cost reflectivity).<br><br>While identifying issues with cost reflectivity of current charges the issue remains unresolved by all proposals.<br><br>Some proposals attempt to freeze net charging levels at a value that is designed by the proposers to be cost reflective. While these are pragmatic approaches for a 'stop-gap' solution - the workgroup has not analysed the basis of the values selected for the frozen tariffs.<br><br>Some base their proposals on locational signal remaining intact: this does not produce a cost reflective signal as retained locational signals are not reflective of SQSS. Flooring locational signal also produces a further distorted locational signal. | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | | | | E) All proposals have a higher admin burden than the baseline due to level of work to support ring fencing of specified customers and application of different sets of tariffs. Change of supplier process and additional flows / central data store required. | |
| Mark Draper* (Nick Sillito) | WACM 19 | This proposal achieves a pause in the incentive to locate new generation on embedded networks allowing for a proper assessment of network charging to take place.<br>It also maintains the incentive to invest in new plant that was awarded 2014 or 2015 CM agreements, the loss of which could cause a supply squeeze in around 2018 and damage competition in the supply and generation of electricity.<br>Its variation over the original proposal of fixing the residual that can be avoided by embedded generation removes the risk of a "price runaway" whilst the assessment is taking place. | Against the current CUSC baseline, no modification provides any improvement. If the Authority were to approve CMP 264 or a CMP 264 WACM then my view would be that the matching CMP 269 modification would better meet the CUSC objectives. | WACM 10 | In my view, this option is very marginally better than the current baseline<br>The option protects the embedded new build already in the market and therefore facilitates competition in the supply and generation of electricity for the next few years, whilst preventing a windfall if the residual charge were to rise as forecast.<br>However, the option does not significantly reduce the embedded benefit to uncommitted new generation, and therefore if there is an issue with the current charging regime it will not prevent incorrect investment decisions from being made whilst a proper | Against the current CUSC baseline, no modification provides any improvement.<br>If the Authority were to approve CMP 265 or a CMP 265 WACM then my view would be that the matching CMP 270 modification would better meet the CUSC objectives. |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | Whilst the modification will make charges to suppliers less cost reflective, its initial impact is relatively low, and this should be balanced by reducing the risk that generation may be locating incorrectly due to issues with the current charging rules. | | | review takes place.<br>In my view, significantly better alternates exist under CMP 264. | |
| Kirsten Gardner* (Adam Heffill) | WACM 8 | The value of Triad payments has increased significantly in recent years and it seems unlikely that the forecast levels of the payment are matched by cost savings to the National Grid. We would agree that this is an issue that needs to be addressed. However, the CUSC modification, or any alternative modifications that may come forward do not address the real problem. Both modification 264 and modification 265 create further distortions and discriminate against embedded generation. Neither modification is an attempt to create a level playing field<br>The issues surrounding charging arrangements and transmission network costs are far more complex than set out in the defect described by CMP265 and should be addressed by Ofgem through a SCR or via a more suitable modification proposal. However, all parties appear to accept that embedded generation provides some grid cost reduction and the value to be paid to embedded generators proposed by WACM 8 (£32.30) is based on sound analysis by an independent group, whose assessment confirms that this would be a cost reflective payment. As such, we believe that WACM 8 best achieves the CUSC objectives. | | WACM 8 | The value of Triad payments has increased significantly in recent years and it seems unlikely that the forecast levels of the payment are matched by cost savings to the National Grid. We would agree that this is an issue that needs to be addressed. However, the CUSC modification, or any alternative modifications that may come forward do not address the real problem. Both modification 264 and modification 265 create further distortions and discriminate against embedded generation. Neither modification is an attempt to create a level playing field<br>The issues surrounding charging arrangements and transmission network costs are far more complex than set out in the defect described by CMP265 and should be addressed by Ofgem through a SCR or via a more suitable modification proposal. However, all parties appear to accept that embedded generation provides some grid cost reduction and the value to be paid to embedded generators proposed by WACM 8 (£32.30) | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | | | | is based on sound analysis by an independent group, whose assessment confirms that this would be a cost reflective payment. As such, we believe that WACM 8 best achieves the CUSC objectives. | |
| Jonathan Graham | CUSC Baseline | a) This proposal and all of the alternatives create new distortions between different types of generation (CM and non-CM; exported and on-site) and between generation and demand reduction, applying different charging methodologies for different demand users. No solution to these distortions and discrimination are foreseeable.<br>b) Insufficient analysis was undertaken regarding the long run marginal cost of distributed generation and whether this is reflected by the current locational charge. However, ADE E is the best assessment available to reflect the avoided cost from distributed generation.<br>(c) The proposal and related alternatives do not address the underlying symptom which is creating a growing demand residual, which is caused by both the growing unallocated cost of transmission networks and the need to better allocate and socialise specific network costs to users.<br>d) The proposal and all of the alternatives apply discrimination between different users does not comply with Directive 2009/72/EC.<br>e) The proposal and all of the alternatives will apply different charging methodologies for different users will create significant administrative costs for suppliers, and later application to on-site generators will create significant new inefficiencies for both suppliers and small generators. Further action will be required to address the demand residual, meaning this modification will apply costs which could be avoided. | | CUSC Baseline | a) This proposal and all of the alternatives create new distortions between different types of generation (CM and non-CM; exported and on-site) and between generation and demand reduction, applying different charging methodologies for different demand users. No solution to these distortions and discrimination are foreseeable.<br>b) Insufficient analysis was undertaken regarding the long run marginal cost of distributed generation and whether this is reflected by the current locational charge. However, ADE E is the best assessment available to reflect the avoided cost from distributed generation. In lieu of a full review of available analysis, ADE is the most appropriate assessment and better aligns with quantitative evidence provided to the Workgroup by Cornwall Energy, and reduces the risk of changing the charging methodology to a less cost-reflective one.<br>c) The proposal and related alternatives do not address the underlying symptom which is creating a growing demand residual, which is caused by both the growing unallocated cost of transmission networks and the need to better allocate and socialise specific network costs to users. | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
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| | | | | | d) The proposal and all of the alternatives apply discrimination between different users does not comply with Directive 2009/72/EC.<br>e) The proposal and all of the alternatives will apply different charging methodologies for different users will create significant administrative costs for suppliers, and later application to on-site generators will create significant new inefficiencies for both suppliers and small generators. Further action will be required to address the demand residual, meaning this modification will apply costs which could be avoided. | |
| Christopher Granby | WACM 8 | It is one of the few that has some analysis and has attempted to quantify the problem | | WACM 8 | Is one of the few mods which actually attempt some analysis. | |
| John Harmer | WACM 21 | This is considered to provide the best balance between maintaining investor confidence in giving existing investments and commitments the revenue they reasonably forecast, so maintaining the largest pool of investors and providing greater competition by maximising the number of players in the market. It contains a gradual ramp down to a reasonable enduring value through the lack of RPI indexation which is therefore expected to reduce the gap between the grandfathered level and the enduring value. The enduring value is set at a level which has some robust logical basis in giving an undistorted locational signal to new EG whilst maintaining zero or above demand charges so as not to give a disincentive to generate at peak. This value is above the level that TG may reasonably see but this reflects market failure in the inability for small players to access medium term super peak pricing to support financing. It is significantly below the benefit for DSR and BTM competition. It has a cut off date for grandfathering that pragmatically | | WACM 10 | This is considered to provide the best balance between maintaining investor confidence in giving existing investments and commitments the revenue they reasonably forecast, so maintaining the largest pool of investors and providing greater competition by maximising the number of players in the market. It contains a gradual ramp down to a reasonable enduring value through the lack of RPI indexation which is therefore expected to reduce the gap between the grandfathered level and the enduring value. The enduring value is set at a level which has some robust logical basis in giving an undistorted locational signal to new EG whilst maintaining zero or above demand charges so as not to give a disincentive to generate at peak. This value is above the level that TG may | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | reflects the timescales for delivery of yet to be constructed assets to meet existing commitments.<br>It probably gives a lower cost to consumers than the original 264 mod by limiting the rise in demand residual that would otherwise be received by existing EG, though this is a speculative assertion as it depends on the relative volume of Affected versus Grandfathered EG. It certainty gives a lower cost than the CUSC baseline. It is thus better than the baseline in terms of objective (b).<br>It provides an outcome that does not cause the embedded benefit to rise with increasing OFTO and onshore transmission reinforcement. It therefore is better than the baseline in terms of objective (c).<br>It is no better or worse than the baseline or Original in terms of objective (d).<br>It has no more complexity than other WACMs that require grandfathering and it is demonstrably amongst the simplest in legal drafting. It is no worse than the Original but in common with all WACMs and the Original it is worse than the baseline in terms of objective (e). | | | reasonably see but this reflects market failure in the inability for small players to access medium term super peak pricing to support financing. It is significantly below the benefit for DSR and BTM competition. It has a cut off date for grandfathering that pragmatically reflects the timescales for delivery of yet to be constructed assets to meet existing commitments.<br>This is considered to provide a compromise that spreads the competitive distortion relatively evenly between TG, EG, behind the meter generation and DSR so is optimum in terms of objective (b).<br>It probably gives a lower cost to consumers than the original 269 mod by limiting the rise in demand residual that would otherwise be received by existing EG, though this is a speculative assertion as it depends on the relative volume of Affected versus Grandfathered EG. It certainty gives a lower cost than the CUSC baseline.<br>It provides an outcome that does not cause the embedded benefit to rise with increasing OFTO and onshore transmission reinforcement.<br>It is no better or worse than the baseline or Original in terms of objective (c).<br>It has no more complexity than other WACMs that require grandfathering and it is demonstrably amongst the simplest in legal drafting. It is no worse than the Original but in common with all WACMs and the Original it is worse than the baseline in terms of | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
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| | | | | | objectives (a) and (d). | |
| Simon Lord | WACM 3 | As has been demonstrated to the working group using the full transport and tariff model there is only a marginal difference between the cost to the transmission system uses of the connection of distributed generation and transmission connected generation at the same location. This proposal that advocate an embedded benefit of a fixed charge of ~£1.62 (the avoided Grid Supply Point reinforcement cost) plus the locational it is seen as cost reflective and we support this proposal | | WACM 3 | As has been demonstrated to the working group using the full transport and tariff model there is only a marginal difference between the cost to the transmission system uses of the connection of distributed generation and transmission connected generation at the same location. This proposal that advocate an embedded benefit of a fixed charge of ~£1.62 (the avoided Grid Supply Point reinforcement cost) plus the locational it is seen as cost reflective and we support this proposal. | |
| Graz McDonald* (Jeremy Taylor) | WACM 10 | It fixes the problem, it will keep the lights on, it will maintain stability and it will benefit consumers. | | WACM 10 | It fixes the problem, it will keep the lights on, it will maintain stability and it will benefit consumers. | |
| Rob Marshall | WACM 6 | Does not introduce discrimination between embedded generators<br>• Increases cost reflectivity by removing the non cost reflective demand residual<br>• Uses the indicative locational signal to represent the value of embedded generation avoiding the cost of network reinforcement<br>• Efficient methodology to implement | | WACM 6 | Does not introduce discrimination between embedded generators<br>• Increases cost reflectivity by removing the non cost reflective demand residual<br>• Uses the indicative locational signal to represent the value of embedded generation avoiding the cost of network reinforcement<br>• Efficient methodology to implement | |
| Paul Mott | WACM 3 | Uniper A uses grid's figure for avoided GSP cost for the true benefit "X". Lacking phasing or grandfathering, giving good benefit – best overall – | I understand that the proposer has included an attempt to identify what he contends to be the "correct" value for benefits (avoided GSP switchgear costs, re-assessed each price control). I am | CMP265 Original | Statement of defect of CMP265 is to address a distortion in the CM. This mod does exactly that, none of the WACMs does as they all affect other plant too, thus less accurately meeting the statement of defect. Against its own statement of defect, it is excellent | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
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| | | and the lack of grandfathering also slightly eases administration/implementation of this option. I see no rationale for flooring, though, as the locational charge and how it is applied, is supposed to be cost-reflective and its application should just be put right if it were established to be not cost-reflective. | open-minded but warm to this concept; it is better than the other ideas, which seem to lack justification, around what "X" should be. There is no grandfathering, and no phasing, enabling quick consumer benefits, and efficient, simple implementation; therefore best option re : CMP264/269 | | | |
| Andy Pace | WACM 9 | This is the preferred option as it sets the level of the demand residual to be used for embedded generation at a level that provides a reasonable level of compensation to existing and new plant while allowing for a more thorough review of embedded benefits to take place, particularly in the area of connection charges and the calculation of the locational charge. | | WACM 9 | This is the preferred option as it sets the level of the demand residual to be used for embedded generation at a level that provides a reasonable level of compensation to existing and new plant while allowing for a more thorough review of embedded benefits to take place, particularly in the area of connection charges and the calculation of the locational charge. | |
| Guy Phillips* (Paul Jones) | WACM 3 | Discrimination on basis of being embedded is removed and a more cost reflective charge replaces it. The avoided GSP charge is the only embedded benefit which has been demonstrated to exist over and above the locational charge. Does not have the administrative complexities associated with grandfathering. | | WACM 3 | Discrimination on basis of being embedded is removed and a more cost reflective charge replaces it. The avoided GSP charge is the only embedded benefit which has been demonstrated to exist over and above the locational charge. Does not have the administrative complexities associated with grandfathering. | |
| Bill Reed | CUSC Baseline | The proposals and the alternatives will not better meet the relevant CUSC Objectives for the reasons | To the extent both these mods facilitate implementation of other mods then these better meet Objective d. (Administrative efficiency) | CUSC Baseline | The proposals and the alternatives will not better meet the relevant CUSC Objectives for the reasons | To the extent both these mods facilitate implementation of other mods then these better |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | outlined in relation to each modification proposal. Furthermore, I am concerned that any views against the applicable objectives may be unsafe. In particular I would highlight the following:<br>1. The modification proposals and their alternatives raise issues associated with discrimination (before/after a date, new/existing, capacity market contracts/non cm contracts, exporting/behind the meter). While the proposers have sought to justify their option, the working group has not evaluated the specific proposals and the potential impact on the wider market arising through the distortions associated with discrimination;<br>introduce significant administrative complexity for suppliers and impact significantly on supplier | | | outlined in relation to each modification proposal. Furthermore, I am concerned that any views against the applicable objectives may be unsafe. In particular I would highlight the following:<br>1. The modification proposals and their alternatives raise issues associated with discrimination (before/after a date, new/existing, capacity market contracts/non cm contracts, exporting/behind the meter). While the proposers have sought to justify their option, the working group has not evaluated the specific proposals and the potential impact on the wider market arising through the distortions associated with discrimination;<br>introduce significant administrative complexity for | meet Objective d. (Administrative efficiency) |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
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| | | commercial relationships with customers. These effects have not been assessed fully and we do not have a full understanding of the implications of these changes for the wider electricity market;<br>3. The modification proposals and their variants introduce further distortions into the electricity market through for example flooring or use of the generation residual for demand customers. It is clear that there is the potential for a significant move away from cost reflectivity in all of the proposals, and I do not believe that this has been well understood by the group;<br>4. The concentration on developing alternatives has taken away the possibility of properly evaluating the proposals based on evidence and wider consultation given the accelerated timescales; | | | suppliers and impact significantly on supplier commercial relationships with customers. These effects have not been assessed fully and we do not have a full understanding of the implications of these changes for the wider electricity market;<br>3. The modification proposals and their variants introduce further distortions into the electricity market through for example flooring or use of the generation residual for demand customers. It is clear that there is the potential for a significant move away from cost reflectivity in all of the proposals, and I do not believe that this has been well understood by the group;<br>4. The concentration on developing alternatives has | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | and<br>5. The development of options to place in front of the authority is an area of concern. I do not believe that the creation of options is compatible with the CUSC objectives or with the efficiency of the CUSC process. | | | taken away the possibility of properly evaluating the proposals based on evidence and wider consultation given the accelerated timescales; and<br>5. The development of options to place in front of the authority is an area of concern. I do not believe that the creation of options is compatible with the CUSC objectives or with the efficiency of the CUSC process. | |
| John Tindal | WACM 5 | Treats all the same<br>Gross demand Residual is more cost reflective<br>Generator residual element better for competition<br>GSP avoidance likely to be more cost reflective<br>3 year phasing helps implementation | | WACM 5 | Treats all the same<br>Gross demand Residual is more cost reflective<br>Generator residual element better for competition<br>GSP avoidance likely to be more cost reflective<br>3 year phasing helps implementation | |
| Matthew Tucker | WACM10 | Halts escalation of demand residual which would otherwise eventually lead to distortions in competition. Treats all DG the same and simplifies administration over the original proposal. Avoids creating winners and losers | | WACM10 | Halts escalation of demand residual which would otherwise eventually lead to distortions in competition. Treats all DG the same and simplifies administration over the original proposal. Avoids creating winners and | |

| WG member | CMP264/269 Option voted best | CMP264 vote 3 rationale | CMP269 vote 3 rationale | CMP265/270 Option voted best | CMP265 vote 3 rationale | CMP270 vote 3 rationale |
|---|---|---|---|---|---|---|
| | | amongst DG as a result of the proposal. | | | losers amongst DG as a result of the proposal. | |
| Joseph Underwood | WACM 3 | rom the evidence seen and the given time to review, I believe WACM3 best facilitates the ACOs. Locational and GSP reinforcement costs seems like the most reasonable approximation of the true value for EB. It will therefore better facilitate competition between TG and EG, it will reflect more accurately the true value of EBs and in doing so will reduce the distortion seen through the current excessive EB.<br>I would also like to note that the precedence set under CMP213, the notice for charging changes was one full charging year and therefore under the argument for grandfathering and phasing has not been made in this circumstance and will introduce undue discrimination between generators. | | WACM 3 | From the evidence seen and the given time to review, I believe WACM3 best facilitates the ACOs. Locational and GSP reinforcement costs seems like the most reasonable approximation of the true value for EB. It will therefore better facilitate competition between TG and EG, it will reflect more accurately the true value of EBs and in doing so will reduce the distortion seen through the current excessive EB.<br>I would also like to note that the precedence set under CMP213, the notice for charging changes was one full charging year and therefore under the argument for grandfathering and phasing has not been made in this circumstance and will introduce undue discrimination between generators. | |
| Lisa Waters | ABSTAINING | No rating to be provided as no analysis to base a decision on | | ABSTAINING | No rating to be provided as no analysis to base a decision on | |
| Sam Wither | WACM 15 | Improves competition, removes discrimination issues of stranding newbuild CM/CfD committed assets from 2014 and 2015 EMR auctions (resulting in savings up to £1.5bn to the end consumer) and improves cost reflectivity with retained locational signals. | | WACM 15 | Improves competition, removes discrimination issues of stranding newbuild CM/CfD committed assets from 2014 and 2015 EMR auctions (resulting in savings up to £1.5bn to the end consumer) and improves cost reflectivity with retained locational signals. | |

* Indicates that the alternate voted

# 12 Workgroup conclusions

12.1 A number of Workgroup members raised concerns that the accelerated timescales proposed under the updated Terms of Reference may mean that only qualitative and not quantitative detailed analysis could be performed in the timescales given. Whilst analysis was presented on various issues by individual Workgroup members, the Workgroup did not conduct its own analysis or come to a consensus on the evidence presented.

12.2 The Workgroup's Terms of Reference require it to capture its conclusions. Given the nature of these Modifications, Workgroup members were unable to reach conclusions that had the consensus of all members. The key arguments of the workgroup members are summarised in the following paragraphs. It should be noted that these views are only supported by subsets of workgroup members.

**Workgroup members who supported stabilisation of charges pending a review and/or grandfathering put forward the following conclusion:**

~~12.3~~ **Cost reflectivity**. Transmission access charging needs to be as transparent, cost reflective and stable/predictable as possible. It is clear that the current arrangements where the locational charge only accounts for about 10% of the allowed transmission revenue and the remaining 90% is allocated into an unexplained residual pot is not satisfactory going forwards. Incorrect pricing signals can lead to sub-optimal investment decisions (either in siting new generation or demand or decisions to retain or close existing generation or demand) and ultimately the costs of suboptimal decisions are reflected in higher costs and ultimately prices for customers. Achieving as cost reflective as possible transmission access pricing is vital to controlling network costs for consumers.

~~12.4~~12.3 **Understanding the residual.** Further, the notion that the D-TNUoS charge can be split into the locational element of the charge that is cost-reflective, and the residual charge that represents a charge to recover the “fixed/sunk” costs of the network is entirely unjustified. The locational element of the charge is only designed to signal differences in the cost demand imposes across different locations, not the absolute level of transmission cost that demand imposes. Whilst the total locational charge only accounts for 10% of the allowed transmission revenue, the demand locational charge nets to a £0 recovery. This therefore implies either that there is no capital investment, maintenance or operational costs incurred on the transmission system as a result of demand or, more likely, that this signal is in fact, not cost-reflective.

~~12.5~~12.4 Charges to use the transmission system should equally reflect the long run marginal costs incurred or avoided from the connection of demand, embedded generation, and transmission connected generation, which the modifications fail to achieve. While there may be logic in ‘socialising’ specific network costs to all generators and demand users, the working group received no evidence on which specific costs should be included in such an approach and why.

~~12.6~~12.5 **Non-discriminatory charging**. Net charging within a GSP (meaning that 1 MW of demand management and 1 MW of embedded generation have the same impact on transmission use and therefore should incur the same charge) appears to be the most cost reflective mechanism for allocating costs within a GSP. The working group evidence shows that a demand user or on-site generator and an embedded generator would face different and therefore discriminatory charging methodologies under the proposed gross charging modifications, despite identical impacts on the network. The work group received no evidence or practical solutions for how these new distortions could be addressed in future. Given the limited analysis undertaken it is likely that there will be further distortions which will create additional unintended consequences. However, it is noted that there are inconsistencies with the current generation charging which should be addressed.

~~12.7~~12.6 **Risk to consumers without an evidence-based approach.** Whilst it is self-evident that cost-reflective and non-discriminatory charging is likely to be the most efficient approach, the determination of what is and is not cost reflective should only be based upon analysis and evidence. In the workgroup we have been presented with various pieces of analysis suggesting different costs / values for the use of the transmission system, although notably the proposer and related parties have not provided any evidence on the long run marginal cost impacts of distributed generation. Estimates have also been provided on the risk to security of supply if even a small proportion of the 7.5 GW of embedded generation stops generating at peak demand, and the negative impacts on consumers from higher Capacity Market costs (estimated by Cornwall Energy as a minimum cost of £282m in 2016), higher wholesale power prices, and higher balancing services costs. The work group received no evidence on the cost impacts to suppliers from this change and future necessary interventions, all of which will create significant but un-estimated costs on consumers. Taken together, it is clear that insufficient analysis has been undertaken to the depth suitable to reach a decision on whether the consumer impacts are better than the baseline. In fact, the existing evidence presented to the work group would indicate that these modifications are just as likely to increase as decrease costs to consumers in the short term. It is informative that the vast majority of industry consultation responses responded against these proposed modifications and many indicated a preference for a more thorough, analytical review. Due to the mix of evidence, if action is taken, it should be biased towards a low-risk, low-change approach.

~~12.8~~12.7 **Strategic approach is lower-risk.** The benefits of taking a more strategic approach in addressing these related issues are not outweighed by the benefits in implementing a bad solution more quickly. As a result of the current CUSC process alongside Ofgem's open letter the industry is now fully aware of the concerns about transmission charging. Any parties making any investment decision are able to factor this uncertainty into their future investment decisions and it is very difficult to justify grandfathering for any investment made after Ofgem's letter was published.

~~12.9~~12.8 **Importance of investor certainty.** Historically, parties have entered into various investments (including CHP, embedded generation and renewable projects) and taken forward looking commitments (15-year capacity market obligations, renewable CfDs etc.) based on the principle that licence exempt generation embedded in the distribution system is charged for its use of the transmission system as negative demand (and the reasonable assumption that this is cost reflective). As noted by a number of consultation respondents, changing this principle, without suitable grandfathering or transitional arrangements, will damage projects potentially reducing security of supply and investor confidence, both of which will ultimately result in higher prices for end users.

**Workgroup members who believed an economic case had been made to adjust the residual element of the TNUoS Embedded Benefits put forward the following views:**

~~12.10~~12.9 Workgroup members supporting reductions in TNUoS Embedded Benefits believed no justification for the current levels had been identified in the Workgroup process. These members felt that the locational tariffs derived from National Grid's transport model reflected the marginal benefit (or cost) of transmission network users, including embedded generators. The members therefore concluded that enduring tariffs for embedded generators should be much closer in value to the tariffs for transmission connected generators in similar geographical locations, because their respective effects on transmission investment costs are essentially the same. Enduring embedded benefits that conferred financial advantage over transmission connected generators would be contrary to the CUSC objectives of cost reflectivity and effective competition.

~~12.11~~12.10 The same workgroup members believed their views on TNUoS embedded benefit reform were well grounded in established economic theory. Under non-discriminatory cost reflective conditions, parties aiming to maximise the net benefits of their projects/assets will correctly account for the impact they have on transmission network costs when making decisions to invest, dispatch, close, compete for contracts etc. All else equal, projects/assets with a lower underlying cost impact on the transmission network will out-compete those with a higher underlying cost impact on the transmission network. This ultimately ensures that consumers pay less for their electricity, because more efficient projects/assets will succeed over less efficient ones when competing against each other. By contrast, non-cost reflective and discriminatory conditions will tend to create “winners” according to who is most favoured by the discrimination. The more discriminatory the conditions, the more market outcomes will move away from a least cost solution, because the discrimination has ever greater potential to distort and reverse underlying cost advantages.

~~12.12~~12.11 The same members believe that evidence has been presented to the working group and contained in this report that demonstrated that:

- Flows on the transmission system are identical following the connection of an equal volume of distribution or transmission connected generation at the same location.
- The size of the transmission system (and hence the cost) is effected by the location of the connection point and is independent of the how the generation is connected i.e. distribution and transmission connected generation have the same effect on the transmission system.
- In general a larger transmission system will be needed to accommodate generation if it is connected independently of a locational signal. It is recognised that the current embedded benefit regime does not provide a strong locational signal.
- Demand customers pay an additional premium above the cost required to fund available TNUoS to pay embedded benefits to distribution connected generation

~~12.13~~12.12 The group also received a detailed presentation from National Grid on the derivation of the locational element of the TNUoS charge detailing how these costs are derived. All non- locational TO and SO costs are recovered via the residual charge, that represents the balance of costs allowed by Ofgem through the price control. A breakdown of this is publically available.

~~12.14~~12.13 The same members opposed WACMs featuring grandfathering of TNUoS rates for similar reasons to the above. TNUoS charges are supposed to be cost reflective and facilitate effective competition. The members believed that allowing certain embedded generators continued access to preferential TNUoS rates for reasons unrelated to their underlying cost impact on the transmission network would be contrary to the CUSC objectives and the interests of consumers. However, to varying degrees, the members were sympathetic to some degree of lag between a decision to reduce TNUoS embedded benefits and the date from which the reductions would apply.

~~12.15~~12.14 Workgroup members who believed an economic case had been made felt that the distortions caused by excessive TNUoS embedded benefits are likely to manifest in the following ways:

- Investment decisions are artificially skewed in favour of embedded generation and away from transmission connected generation for reasons unrelated to underlying cost advantages.
- Embedded generation has strong incentives to dispatch over potential TRIAD periods, irrespective of whether they are in a favourable location (from a TNUoS perspective) and irrespective of whether they are in merit in the energy market.

- Embedded generators' ability to out-bid transmission connected generators in the Capacity and ancillary service markets (because of their embedded benefits) means that contracts are likely being allocated to parties out of merit order.
- Innovation in the electricity markets is distorted as market participants are pre-occupied with maximising their embedded benefits instead of focussing on genuine value adding activities that benefit consumers.

**Members who believed that insufficient evidence or analysis has been put forward to come to a conclusion identified the following concerns:**

~~12.16~~12.15 The majority of the Workgroup had concerns that the accelerated timetable for developing the Modifications and proposed alternatives, would not allow for an substantive analysis to be undertaken. While a number of parties tried to provide analysis around specific impacts of the Modifications (for example changes in wholesale prices), this was not work undertaken and reviewed by the Workgroup. A number of Workgroup members believed that the effects of the changes could be so far reaching, that it would be beholden on Ofgem to undertake analysis prior to agreeing to any change

~~12.17~~12.16 The lack of robust analysis means that many of the potential impacts of each proposal are not quantified, though the report tries to describe the impacts in a qualitative manner. Many Workgroup members had their own view on the direction of travel of each impact and the group tried to capture these.

~~12.18~~12.17 It was noted that locational prices send useful signals but that they are very difficult, if not impossible, to respond to due to the wider issues associated with the lack of capacity (both distribution and transmission) where parties are being signalled to connect.

~~12.19~~12.18 It was unclear if the Transmission Owner's networks could cope with a dramatic change in the pattern of flows. In addition the Workgroup did not receive views from Distribution Network Owners and were therefore unable to determine if change of flows would impact their networks.

~~12.20~~12.19 The Workgroup also noted that the CUSC objectives are more limited than Ofgem's duties. For example, the Workgroup did not analyse changes in the merit order, and thus the way plants will operate depending on the any change approved. Ofgem would have to consider the effect on competition, as required by the CUSC, but also the impact on emission, as required by its wider duties.

**In summary the Workgroup agreed that this report be submitted to the CUSC Panel noting that no consensus was reached within the Workgroup.**

# 13 Impact and Assessment

## Impact on the CUSC

13.1 Changes to Section 11 and 14 – please refer to section 10 and Annex 4 for the legal text changes.

## Impact on Greenhouse Gas Emissions

13.2 The workgroup has not assessed the impact on Greenhouse Gas Emissions.

## Impact on Core Industry Documents

13.3 None

## Impact on other Industry Documents

13.4 There is likely to be an impact on the Balancing and Settlement Code, to provide the required data flows.

(a) In particular P349: Facilitating embedded generation Triad Avoidance Standstill was raised on 4 July, to accompany CMP264, and P348: Provision of gross BM Unit data for TNUoS charging was raised on 1 July to accompany CMP265. ELEXON are involved in the discussion within the CMP264 and CMP265 Workgroups to improve synergies between CMP264/P349 and CMP265/P348.

(b) There may also be consequential changes to the MRA Data Transfer Catalogue (DTC), identified through the related BSC modifications.

## 14 Proposed Implementation and Transition

14.1 The Workgroup discussed implementation on a number of occasions particularly in the development of Workgroup alternatives.

14.2 The implementation of any CUSC Modifications is in the gift of the regulator in that its direction will include notice of the required date of implementation. However, implementation can mean different dates depending on the nature of the change.

14.3 Once directed by Ofgem the implementation usually refers to the date that the text of the CUSC itself is changed and becomes the new requirement to which National Grid and CUSC parties must adhere to.

14.4 For National Grid, implementation needs to include sufficient notice of the change in order to set new transmission tariffs. The tariff setting timetable is a licence requirement with draft tariffs published in December and final tariffs at the end of January. There needs to be sufficient notice of the change in order for National Grid to take account of a different charging base in its analysis that takes place prior to these dates.

14.5 Implementation was considered by some to mean the date from which 'new' is defined, however this was kept separate into the detail of the legal text. For parties looking to understand if they are impacted by the change and when this will be a key date.

14.6 A view was expressed that where the Modification is specific to capacity markets agreement holders, implementation could mean the applicable capacity market year but again parties would need to look at the detail of the legal text to understand this.

14.7 Transmission tariffs are currently set in January for the 12 month period commencing the following April. Charges are then billed to Suppliers and Generators from April - March over the course of the year. Implementation could mean the applicable 'triad season' however due to the nature of the charging year it would not be possible to implement from November in any charging year without a impacting bills that are issued from the April of that year.

14.8 The Workgroup discussed the implementation of these modifications as being the first practicable applicable charging year, noting in particular the need for advance notice for the purposes of tariff setting. The group also acknowledged the views from some consultation responses that three year's notice of implementation would allow for sufficient time to update processes and systems for some Suppliers.

14.9 The Workgroup considered that the first practicable implementation date would be the charging year 2018-19. Some of the modifications and alternatives do intend on a later charging year, noting the proposer’s original intent for CMP265 of an April 2020 implementation.

# Annex 1 – CUSC Proposal forms for CMP264, CMP265, CMP269 and CMP270

# CUSC Modification Proposal Form (for Charging Methodology Proposals) CMPXXX

nationalgrid

## Connection and Use of System Code (CUSC)

### Title of the CUSC Modification Proposal

**Embedded Generation Triad Avoidance Standstill** proposal – Changes to the Transport and Tariff Model and billing arrangements to remove the netting of output from New Embedded Generators until Ofgem has completed its consideration of the current electricity transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented.

### Submission Date

17 May 2016

### Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

The registration of embedded generators to a Supplier BM Unit can result in a reduction in TNUoS charges payable by the supplier. The embedded generators do not pay generation transmission charges and may receive a significant benefit from the supplier whose TNUoS charges they reduce – “Triad avoidance”.

Due to increasing volume of embedded generation output and the growth in the Transmission Owner Allowed Revenues and other monies recoverable through TNUoS, the likely value of Triad avoidance for embedded generators has increased significantly, and under the current charging arrangements is forecast by National Grid Electricity Transmission (“NGET”) to continue to grow. If Triad avoidance (and the future increases) were cost-reflective in terms of the transmission reinforcement avoided by reducing flows from the transmission system to meet demand, then the current arrangements would be in the interest of consumers. However, whilst analysis[1] by NGET suggests that some transmission investment is avoided by such reductions in flows, the savings appear to be around twenty times too small to justify current Triad avoidance values. In that work, NGET determined that the average cost saving was £1.62/kW/year in 2013/14 money, whilst a current estimate[2] of the average value that an embedded generator would receive from Triad avoidance in 2018/19 is around £45/kW/year[3]. Moreover, the results from 5 out of the 18 schemes that were assessed showed cost savings of less than 50p/kW/year.

The existence of large non-cost reflective Triad avoidance values is likely to distort investment decisions by favouring small generation units over large ones that may be more efficient. This could cause more efficient investments which do not benefit from Triad avoidance to be abandoned or deferred while less effective ones, which do so benefit, go ahead. This would increase total system costs, which is likely to lead to higher costs for consumers. Cost reflective charges would lead to better investment decisions and lower costs for consumers.

Ofgem is currently considering these issues[4] and implementation of any resulting changes, eg through a Significant Code Review (SCR), is likely to take some time. In the meantime, distortions to investment could take place based on the current non-cost reflective signals, in part due to Triad avoidance income received during the period of the review. This is likely to lead to inefficient investment in the generation fleet and, over time, higher costs for customers. This risk can be mitigated by suspending access to Triad avoidance for New Embedded Generators until Ofgem's consideration of the current electricity transmission Charging Arrangements (and any review which may ensue) has been completed and any resulting changes have been fully implemented.

This is a proportionate response since current indications are that Triad avoidance values exceed the cost reflective level by a factor of around 20. It follows that temporarily setting them to zero for new embedded generators is likely to be closer to the cost reflective outcome, and more likely to be efficient for consumers, than allowing the current situation to sustain pending Ofgem's consideration of the issues (including any review which may ensue) and implementation of any more comprehensive changes.

[1] National Grid, Review of the Embedded (Distributed) Generation Benefit arising from transmission charges, 20 December 2013.
[2] National Grid outlook January 28th 2015 (http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/)
[3] The current value of Triad management is £30/kW/year, but this is forecast to rise by around £15/kW/year by 2018/19. This estimate excludes the three least lucrative geographical areas - the locational signal may mean that these areas are not targeted by developers.
4 As recently announced by DECC and highlighted in Ofgem's Forward Work Programme 2016-17 paras 2.17 to 2.19

## Description of the CUSC Modification Proposal

This modification aims to limit the detriment from the continuing lack of a level playing field between new embedded generators and other generation plant, by suspending access to Triad avoidance for New Embedded Generators until Ofgem has completed its consideration of the issues (including any review which may ensue) and fully implemented any resulting changes.

New Embedded Generator is defined as any half hourly metered embedded generation unit commissioned after 30 June 2017.

Commissioned is defined as having an MPAN registered and having commenced generation.

The suspension is achieved by removing the netting of output from New Embedded Generators when calculating their demand volumes for use in the setting of tariffs for suppliers in the Transport and Tariff model and for actual billing. As the supplier would no longer benefit from netting the output from these generators there will be no "Triad avoidance" to share with the embedded generator.

It is intended that the changes to the charging methodology made by this modification will be temporary and that no enduring difference of treatment between new and existing generation will be created. Accordingly, the provisions of this modification that change the charging methodology will cease to have effect on the "disapplication date, being the date when Ofgem confirms that it has completed its consideration of the issues (and any review which may ensue) and any resulting changes have been fully implemented.

A BSC amendment would amend the metering data reports to provide the information needed in order to remove the netting for all embedded generators commissioned after 30 June 2017.

## Impact on the CUSC

Changes will be required to Section 14 of the CUSC (Part 2 The Statement of the Use of System Charging Methodology) including, but not necessarily limited to the following:

Tariff Setting

Changes are required to Section 14.15 (Derivation of the Transmission Network Use of System Tariff) to ensure that total User forecast Metered Triad Demand provided by Users and used to set TNUoS tariffs does not net any output from New Embedded Generation.

Billing & Reconciliation

The basis of Demand Charges should be amended to ensure that output from any New Embedded Generators is not netted from Triad demand in the Supplier forecasts used for monthly billing or in the reconciliation process to actual outturn charges.

## Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes / No

*You can find guidance on the treatment of carbon costs and evaluation of the greenhouse gas emissions on the Ofgem's website:*
*http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=196&refer=Licensing/IndCodes/Governance*

We believe that this Proposal is likely to help reduce greenhouse gas emissions. This is as a result of the creation of a level playing field between small embedded generation and larger transmission connected generation. We believe that this is likely to lead to the deployment of more efficient plant which may lead to a corresponding reduction in the emission of greenhouse gasses.

## Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information

**BSC** ☒

**Grid Code** ☐

**STC** ☐

**Other** ☐
*(please specify)*

*This is an optional section. You should select any Codes or state Industry Documents which may be affected by this Proposal and, where possible, how they will be affected.*

The data used in the calculation of Triad demand and chargeable supplier demand volumes is calculated under the Balancing & Settlement Code (BSC) and changes will be required to the BSC to enable the identification of meter data from New Embedded Generators. This meter data should then be excluded when generating the data flows used for TNUoS billing. A separate BSC Issue will be raised to consider the potential changes required from this CUSC modification.

For the avoidance of doubt, metered output from embedded generators will still be netted from Supplier's demand volumes for the purposes of imbalance settlement under the BSC.

**Urgency Recommended: Yes / No**

No.

**Justification for Urgency Recommendation**

*If you have answered yes above, please describe why this Modification should be treated as Urgent. An Urgent Modification Proposal should be linked to an imminent issue or a current issue that if not urgently addressed may cause:*

a) *A significant commercial impact on parties, consumers or other stakeholder(s); or*
b) *A significant impact on the safety and security of the electricity and/or has systems; or*
c) *A party to be in breach of any relevant legal requirements.*

*You can find the full urgency criteria on the Ofgem's website:*
*[http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=213&refer=Licensing/IndCodes/Governance](http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=213&refer=Licensing/IndCodes/Governance)*

**Self-Governance Recommended: Yes / No**

No.

**Justification for Self-Governance Recommendation**

*If you have answered yes above, please describe why this Modification should be treated as Self-Governance.*

*A Modification Proposal may be considered Self-governance where it is unlikely to have a material effect on:*

- *Existing or future electricity customers;*
- *Competition in generation or supply;*
- *The operation of the transmission system;*
- *Security of Supply;*
- *Governance of the CUSC*

- *And it is unlikely to discriminate against different classes of CUSC Parties.*

**Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?**

*Please justify whether this modification should be exempt from any Significant Code Review (SCR) undertaken by Ofgem. You can find guidance on the launch and conduct of SCRs on Ofgem's website, along with details of any current SCRs at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=197&refer=Licensing/IndCodes/Governance. For further information on whether this Proposal may interact with any ongoing SCRs, please contact the Panel Secretary.*

Yes. We are not aware of any current Significant Code Review (SCR) whose scope overlaps with the scope of this modification. If Ofgem opens an SCR which includes embedded generation Triad avoidance, this modification should be considered exempt because of its temporary/transitional nature.

**Impact on Computer Systems and Processes used by CUSC Parties:**

Suppliers will need to amend their internal systems to exclude the output from New Embedded Generators when preparing demand forecasts as required under S14 of the CUSC and when validating TNUoS bills received from National Grid.

**Details of any Related Modification to Other Industry Codes**

A BSC Modification will be required to provide the necessary data to facilitate this charging proposal. We shall raise a BSC Issue for consideration.

**Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:**

**Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.**

**Use of System Charging Methodology**

☒ (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

☒(b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

☒ (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

☐ (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

**Full justification:**

Charging Objective (a)

This modification will mitigate the effects of the current lack of a level playing field between investing in embedded generators and transmission connected (and large embedded) generators during the period of Ofgem's review, thus better facilitating competition in the generation and supply of electricity.

Charging Objective (b)
Given the low levels of actual cost savings realised through the Triad management schemes, the suspensory action would ensure that, in respect of New Embedded Generators during the period of Ofgem's review, charges would better reflect costs.

Charging Objective (c)

Developments in the transmission system have led to an increase in Triad values, thus increasing the distortions created by embedded generation Triad avoidance to an unsustainable level. This modification mitigates the effect of this by temporarily removing distortion of investment decisions until Ofgem has completed its consideration of the issues (including any review which may ensue) and fully implemented any resulting changes.

Charging Objective (d)

The proposer believes that the proposal is neutral against applicable charging objective (d).

**Connection Charging Methodology**

☐ (a) that compliance with the connection charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

☐ (b) that compliance with the connection charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

☐ (c) that, so far as is consistent with sub-paragraphs (a) and (b), the connection charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;

☐ (d) in addition, the objective, in so far as consistent with sub-paragraphs (a) above, of facilitating competition in the carrying out of works for connection to the national electricity transmission system.

☐ (e) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

*Objective (e) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

**Full justification:**

The Proposal does not impact on the Connection Charging Methodology

## Additional details

| | |
|---|---|
| **Details of Proposer:** (Organisation Name) | ScottishPower Energy Management Limited |
| **Capacity in which the CUSC Modification Proposal is being proposed:** (i.e. CUSC Party, BSC Party or "National Consumer Council") | CUSC Party |
| **Details of Proposer's Representative:**<br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address: | <br>Rupert Steele<br>Director of Regulation, ScottishPower<br>0141 614 2012<br>Rupert.Steele@ScottishPower.com |
| **Details of Representative's Alternate:**<br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address: | <br>James Anderson<br>ScottishPower Energy Management Limited<br>0141 614 3006<br>James.Anderson@ScottishPower.com |
| **Attachments (Yes/No):**<br>**If Yes, Title and No. of pages of each Attachment:** | No |

## Contact Us

If you have any questions or need any advice on how to fill in this form please contact the Panel Secretary:

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

For examples of recent CUSC Modifications Proposals that have been raised please visit the National Grid Website at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/

## Submitting the Proposal

Once you have completed this form, please return to the Panel Secretary, either by email to jade.clarke@nationalgrid.com copied to cusc.team@nationalgrid.com, or by post to:

Jade Clarke
CUSC Modifications Panel Secretary, TNS
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If no more information is required, we will contact you with a Modification Proposal number and the date the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, the Proposal can be rejected. You will be informed of the rejection and the Panel will discuss the issue at the next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform you.

# CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP265

nationalgrid

## Connection and Use of System Code (CUSC)

| Title of the CUSC Modification Proposal |
|---|
| Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market |
| **Submission Date** |
| 19 May 2016 |
| **Description of the Issue or Defect that the CUSC Modification Proposal seeks to address** |

It is important that costs are allocated fairly as the generation mix evolves. The current TNUoS arrangements will distort the development of an economic generation mix and transmission system, distort the capacity market and continue to provide a cross subsidy between customer groups.

There is a pressing issue related to the next capacity market tender (December 2016) which means that this modification is narrow and focussed to allow the modification to be considered and determined in advance of this auction. We recognise that further changes may be needed to the TNUoS arrangements which are important but less urgent. Ofgem are likely to reach a conclusion on further charging reforms in summer 2016 and further reforms will also be a focus of National Grid's planned charging review.

Specifically, half hourly metered (HH) demand for TNUoS purposes is currently charged <u>net</u> of embedded generation. The existing CUSC sets this out as follows: "*Netting off within a BM Unit : 14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based*."

This Net demand charging means that embedded generation is being treated as negative demand for HH TNUoS demand charging purposes. The TNUoS charge can be considered as being made up of two elements :

1. A locational element reflecting the unit cost of transmission investment at a point on the GB system. At a simplified level the locational elements for generation and demand users can be considered broadly equal and opposite. Through its netting, an embedded generator can be considered to have an implicit value equal but opposite to the demand signal, and therefore equivalent to the signal received by a transmission connected generator. Given this, netting off the volume is reasonable..

2. A residual element added on a capacity basis (£/kW, irrespective of location) to ensure

TNUoS charges recover the correct revenue. This element does not reflect cost and is worth around £40/kW.

Charging demand on a net basis means that some of the gross HH demand will not pay the residual, and neither will the embedded generation that nets off that demand.

The effect of the net demand charging basis is thus that the value of the demand residual charge element is credited to the embedded generation, where there is an association with an embedded generator as part of that Supplier's portfolio in that GSP group. This is not cost-reflective, as there is no logical reason for that credit, which is growing, to be given.

Netting-off the output of embedded generation for the purpose of calculating these HH demand charges, is causing a distortion in the generation market; to the extent that they run at times of triad, embedded generators are given an artificial advantage over others, which among other effects, distorts the outcome of the capacity market tenders.

This is most strongly apparent for controllable embedded generators that run at peak times due to the structure of the TNUoS charge. These generators are most likely to secure the majority of the avoided residual charge. It is these controllable embedded generators that are also competing in the Capacity Market and run at similar times. Correcting this defect needs to be addressed urgently in advance of the next CM auction (December 2016).

The defect therefore lies in this unwarranted distortion of capacity market tenders. The charging treatment of these generators is not reasonably reflecting transmission network costs and therefore fails against the objectives of the charging methodology. The implication of this is that it distorts competition in generation.

## Description of the CUSC Modification Proposal

It is proposed that half hourly demand residual TNUoS charges on each Supplier in the relevant GSP Group, should be levied according to gross half hourly metered demand, without the volume from embedded generation that is in the capacity mechanism being netted-off. The scope of the modification is limited to only embedded generation with capacity market contracts. Volume associated with embedded generation that does not have capacity market contracts will continue to be netted.

It is proposed that half hourly demand locational TNUoS charges on each Supplier in the relevant GSP Group, should still be levied in relation to the net demand, i.e. with embedded generation being netted-off as at present to enable this cost reflective signal to be maintained.

As to the implementation timescale, we do not propose "grandfathering" which has not been an approach taken to charging modifications (it adds complexity and dilutes the effect of a change). We propose that this change would take effect from 1 April 2020, for all such generators. It is likely that a new data flow is needed to Grid to facilitate this; we are proposing to raise a BSC Modification to ensure that this flow exists. This is a significant modification proposal and a lead time of several charging years before the proposed change takes effect seems sensible to allow parties time to adjust, recognising that some future investments have not been made yet. The next capacity market auction (for winter 2020/21) takes place in

December.

## Impact on the CUSC ( This is an optional section)

To be identified at workgroup. New section 11 definitions are likely to be needed; parts of section 14 are likely to need amendment.

## Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes / No

Nothing quantified.

## Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information

**BSC** **Yes**

**Grid Code** ☐

**STC** ☐

**Other** ☐
*(please specify)*

*This is an optional section. You should select any Codes or state Industry Documents which may be affected by this Proposal and, where possible, how they will be affected.*

## Urgency Recommended: Yes

Yes.

## Justification for Urgency Recommendation

This Modification Proposal is linked to an imminent issue or a current issue that if not urgently addressed may cause a significant commercial impact on parties, consumers or other stakeholder(s). The next capacity market auction (for winter 2020/21) takes place in December; the present arrangements give an artificial advantage to embedded generators, distorting the capacity market. We therefore propose a full but expedited process that ensures that the issues are carefully considered by industry and workgroup, but that the modification proposal reaches Ofgem for decision in September.

*Urgency criteria show on the Ofgem's website at :*
[http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=213&refer=Licensing/IndCodes/Governance](http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=213&refer=Licensing/IndCodes/Governance)

## Self-Governance Recommended: No

No

## Justification for Self-Governance Recommendation

*A Modification Proposal may be considered Self-governance where it is unlikely to have a material effect on :*

- *Existing or future electricity customers;*
- *Competition in generation or supply;*
- *The operation of the transmission system;*
- *Security of Supply;*
- *Governance of the CUSC*
- *And it is unlikely to discriminate against different classes of CUSC Parties.*

## Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?

Yes, there are no relevant SCRs

## Impact on Computer Systems and Processes used by CUSC Parties:

*This is an optional section. Include a list of any relevant Computer Systems and Computer Processes which may be affected by this Proposal, and where possible, how they will be affected.*

## Details of any Related Modification to Other Industry Codes

We will be raising a relevant BSC modification to ensure the necessary data flows are available to National Grid.

## Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:

**Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.**

**Use of System Charging Methodology**

Yes (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

Yes (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

Yes (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

No (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

*Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

**Full justification:**

The modification would better facilitate competition between transmission-connected and embedded generators with particular reference to the Capacity Market. It would remove an artificial distortion that does not reflect the costs of the transmission business and currently gives extra value to embedded generators. The present arrangements are not cost-reflective as there is no logic to netting-off the output of embedded generators from HH demand as far as the demand residual charge element is concerned. As to developments in transmission licensees' transmission businesses – there has been a marked growth in the amount of embedded generation impacting the ways the system is developed and operated – this distortion may have been a contributory factor to that.

## Additional details

| | |
|---|---|
| **Details of Proposer:** (Organisation Name) | Paul Mott |
| **Capacity in which the CUSC Modification Proposal is being proposed:** (i.e. CUSC Party, BSC Party or "National Consumer Council") | CUSC Party |
| **Details of Proposer's Representative:** Name: Organisation: Telephone Number: Email Address: | Paul Mott, EDF Energy, 02031262314 paul.mott@edfenergy.com |
| **Details of Representative's Alternate:** Name: Organisation: Telephone Number: Email Address: | Mark Cox<br>EDF Energy<br>07967151272<br>Mark.cox@edfenergy.com |
| **Attachments (No):** **If Yes, Title and No. of pages of each Attachment:** | |

# CUSC Modification Proposal Form CMP269

Connection and Use of System Code (CUSC)

**Title of the CUSC Modification Proposal**

Potential consequential changes to the CUSC as a result of CMP264

**Submission Date**

19 August 2016

Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

In May 2016, CMP264 (Embedded Generation Triad Avoidance Standstill proposal – Changes to the Transport and Tariff Model and billing arrangements to remove the netting of output from New Embedded
Generators until Ofgem has completed its consideration of the current electricity transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented' was raised by Scottish Power.

As part of the Workgroup analysis, the Workgroup identified that whilst this was a charging modification (which if approved would require change to aspects of section 14 - Charging Methodologies of the CUSC) there are in fact some references outside section 14 of the CUSC that would require change should CMP264 be approved.

However these could not be addressed via CMP264 as it is a charging modification seeking to amend Section 14 of the CUSC and therefore will be assessed against the Applicable Charging Objectives. Any modifications to the CUSC outside of Section 14 – Charging Methodologies are assessed against the CUSC Objectives (not Charging).

Consequently this modification has been raised to detail the required changes to Section 3 and Section 11 of the CUSC. It is suggested that this Modification is amalgamated with CMP264, and the detailed CUSC changes be taken forward should CMP264 be approved.

**Description of the CUSC Modification Proposal**

Changes to Section 14 (Charging Methodologies) under CMP264 will make changes to the charging methodology to calculate demand tariffs and embedded benefits on the basis of structures proposed under the original and any WACMs.

However, changes will also be required to Section 3 (Use of System) and Section 11 (Interpretation and Definitions). The full details of the legal text changes for CMP264 have not yet been prepared by the workgroup (and they are intending to hold a subgroup to do so, after the workgroup consultation closes), however, based on discussions at the workgroup we would expect changes to the other sections are as follows:

Section 3: changes will be required to reflect any change in the structure of tariffs in Section 14, and to ensure obligations on suppliers and the Company in terms of data for forecasting and billing are aligned to those required in order to set tariffs.

Section 11: the proposal will require new definitions such as New Embedded Generation (i.e. those who qualify for a different value of embedded benefit under the CMP264 Original) [Capacity Market Embedded Generation (i.e. those who embedded generators who hold a capacity market agreement)] in order for these terms to be in Section 14 and Section 11 of the CUSC consistently.

Changes to other sections (other than 14, 3 and 11) may also be required for consistency but none have been identified to date.

The expectation of the CMP264 Workgroup is that the discussion relating to the solution for the obligations (in Section 3) and definitions (in Section 11) have and will continue to take place under the CMP264 Workgroup and that this new modification proposal is a procedural device to enable the legal text changes to sections of the CUSC not covered by the use of system charging objectives.

**Impact on the CUSC**

Changes will be required for sections 14, 3 and 11 and there may be other changes required for consistency but none have been identified to date.

Should CMP264 be approved, a number of changes would be required to reflect the CMP264 Proposal or any alternative proposals agreed by the CMP264 Workgroup.

The amendments required are to be developed by the CMP264 Workgroup and depending on whether the Proposer changes its Original Proposal or any alternatives are agreed, the Workgroup may consider with Code Administrator's advice whether any other parts of the CUSC need amendment.

**Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes / No**

**No**

**Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information**

**BSC** ☐

**Grid Code** ☐

**STC** ☐

**Other** ☐
*(please specify)*

There may be an impact on the BSC but this may potentially be covered via CMP264.

**Urgency Recommended: Yes / No**

**No**

**Justification for Urgency Recommendation**

*n/a*

**Self-Governance Recommended: Yes / No**

**No**

**Justification for Self-Governance Recommendation**

*n/a*

**Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?**

There are no relevant SCRs in process.

**Impact on Computer Systems and Processes used by CUSC Parties:**

No impact

Details of any Related Modification to Other Industry Codes

CMP264 '**Embedded Generation Triad Avoidance Standstill** proposal – Changes to the Transport and Tariff Model and billing arrangements to remove the netting of output from New Embedded
Generators until Ofgem has completed its consideration of the current electricity transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented'

| Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives: |
|---|
| *This section is mandatory. You should detail why this Proposal better facilitates the Applicable CUSC Objectives compared to the current baseline. Please note that one or more Objective must be justified.*<br><br>**Please tick the relevant boxes and provide justification:**<br><br>☒ (a) the efficient discharge by The Company of the obligations imposed upon it by the Act and the Transmission Licence<br><br>☒ (b) facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.<br><br>☒ (c) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.<br>These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.<br><br>Objective (c) was added in November 2011. This refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER). |

## Additional details

| | |
|---|---|
| **Details of Proposer:** (Organisation Name) | Scottish Power Energy Management Limited |
| **Capacity in which the CUSC Modification Proposal is being proposed:** (i.e. CUSC Party, BSC Party or "National Consumer Council") | CUSC Party |
| **Details of Proposer's Representative:**<br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address: | <br>Rupert Steele<br>Director of Regulation, Scottish Power<br>0141 614 2012<br>**Rupert.Steele@ScottishPower.com** |
| **Details of Representative's Alternate:**<br>Name:<br>Organisation:<br>Telephone Number:<br>Email Address: | James Anderson<br>Scottish Power Energy Management Limited<br>0141 614 3006<br>James.Anderson@ScottishPower.com |
| **Attachments (Yes/No):**<br>**If Yes, Title and No. of pages of each Attachment:** | |

## Contact Us

If you have any questions or need any advice on how to fill in this form please contact the Panel Secretary:

E-mail cusc.team@nationalgrid.com

Phone: 01926 654028

For examples of recent CUSC Modifications Proposals that have been raised please visit the National Grid Website at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/Current/

## Submitting the Proposal

Once you have completed this form, please return to the Panel Secretary, either by email to heena.chauhan@nationalgrid.com and copied to cusc.team@nationalgrid.com, or by post to:

Heena Chauhan
CUSC Modifications Panel Secretary,
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If no more information is required, we will contact you with a Modification Proposal number and the date the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, the Proposal can be rejected. You will be informed of the rejection and the Panel will discuss the issue at the next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform you.

# CUSC Modification Proposal Form CMP270

nationalgrid

## Connection and Use of System Code (CUSC)

| Title of the CUSC Modification Proposal |
|---|
| Potential consequential changes to the CUSC as a result of CMP265 |
| **Submission Date** |
| 19 August 2016 |
| **Description of the Issue or Defect that the CUSC Modification Proposal seeks to address** |
| In May 2016, CMP265 (Gross charging of TNUoS for HH demand where embedded generation is in the Capacity Market) was raised by EDF Energy.<br><br>As part of the Workgroup analysis, the Workgroup identified that whilst this was a charging modification (which if approved would require change to aspects of section 14 - Charging Methodologies of the CUSC) there are in fact some references outside section 14 of the CUSC that would require change should CMP265 be approved.<br><br>However these could not be addressed via CMP265 as it is a charging modification seeking to amend Section 14 of the CUSC and therefore will be assessed against the Applicable Charging Objectives. Any modifications to the CUSC outside of Section 14 – Charging Methodologies are assessed against the CUSC Objectives (not Charging).<br><br>Consequently this modification has been raised to detail the required changes to Section 3 and Section 11 of the CUSC. It is suggested that this Modification is amalgamated with CMP265, and the detailed CUSC changes be taken forward should CMP265 be approved. |
| **Description of the CUSC Modification Proposal** |
| Changes to Section 14 (Charging Methodologies) under CMP265 will make changes to the charging methodology to calculate demand tariffs and embedded benefits on the basis of structures proposed under the original and any WACMs.<br><br>However, changes will also be required to Section 3 (Use of System) and Section 11 (Interpretation and Definitions). The full details of the legal text changes for CMP265 have not yet been prepared by the workgroup (and they are intending to hold a subgroup to do so, after the workgroup consultation closes), however, based on discussions at the workgroup we would expect changes to the other sections are as follows:<br><br>Section 3: changes will be required to reflect any change in the structure of tariffs in Section 14, |

and to ensure obligations on suppliers and the Company in terms of data for forecasting and billing are aligned to those required in order to set tariffs.

Section 11: the proposal will require new definitions such as New Embedded Generation (i.e. those who qualify for a different value of embedded benefit under the CMP265 Original) [Capacity Market Embedded Generation (i.e. those who embedded generators who hold a capacity market agreement)] in order for these terms to be in Section 14 and Section 11 of the CUSC consistently.

Changes to other sections (other than 14, 3 and 11) may also be required for consistency, but none have been identified to date.

The expectation of the CMP265 Workgroup is that the discussion relating to the solution for the obligations (in Section 3) and definitions (in Section 11) have and will continue to take place under the CMP265 Workgroup and that this new modification proposal is a procedural device to enable the legal text changes to sections of the CUSC not covered by the use of system charging objectives.

## Impact on the CUSC

Changes will be required for sections 14, 3 and 11 and there may be other changes required for consistency but none have been identified to date.

Should CMP265 be approved, a number of changes would be required to reflect the CMP265 Proposal or any alternative proposals agreed by the CMP265 Workgroup.

The amendments required are to be developed by the CMP265 Workgroup and depending on whether the Proposer changes its Original Proposal or any alternatives are agreed, the Workgroup may consider with Code Administrator's advice whether any other parts of the CUSC need amendment.

## Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes / No

**No**

## Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information

**BSC** ☐

**Grid Code** ☐

**STC** ☐

**Other** ☐
*(please specify)*

There may be an impact on the BSC but this may potentially be covered via CMP265.

**Urgency Recommended: Yes / No**

**No**

**Justification for Urgency Recommendation**

*n/a*

**Self-Governance Recommended: Yes / No**

**No**

**Justification for Self-Governance Recommendation**

*n/a*

**Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?**

There are no relevant SCRs in process.

**Impact on Computer Systems and Processes used by CUSC Parties:**

No impact

**Details of any Related Modification to Other Industry Codes**

CMP265 'Gross charging of TNUoS for HH demand where embedded generation is in the Capacity Market'

**Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives:**

*This section is mandatory. You should detail why this Proposal better facilitates the Applicable CUSC Objectives compared to the current baseline. Please note that one or more Objective must be justified.*

**Please tick the relevant boxes and provide justification:**

☒ (a) the efficient discharge by The Company of the obligations imposed upon it by the Act and the Transmission Licence

☒ (b) facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.

☒ (c) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

Objective (c) was added in November 2011. This refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER)

## Additional details

| | |
|---|---|
| **Details of Proposer:** (Organisation Name) | Paul Mott |
| **Capacity in which the CUSC Modification Proposal is being proposed:** (i.e. CUSC Party, BSC Party or "National Consumer Council") | CUSC Party |
| **Details of Proposer's Representative:** Name: Organisation: Telephone Number: Email Address: | Paul Mott, EDF Energy, 02031262314 paul.mott@edfenergy.com |
| **Details of Representative's Alternate:** Name: Organisation: Telephone Number: Email Address: | Mark Cox EDF Energy 07967151272 Mark.cox@edfenergy.com |
| **Attachments (Yes/No):** **If Yes, Title and No. of pages of each Attachment:** | |

## Contact Us

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E-mail cusc.team@nationalgrid.com

Phone: 01926 654028

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## Submitting the Proposal

Once you have completed this form, please return to the Panel Secretary, either by email to heena.chauhan@nationalgrid.com and copied to cusc.team@nationalgrid.com, or by post to:

Heena Chauhan
CUSC Modifications Panel Secretary,
National Grid Electricity Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

If no more information is required, we will contact you with a Modification Proposal number and the date the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, the Proposal can be rejected. You will be informed of the rejection and the Panel will discuss the issue at the next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform you.

# Annex 2 – CMP264, CMP265, CMP269 and CMP270 Terms of Reference

# Workgroup Terms of Reference and Membership

## TERMS OF REFERENCE FOR CMP 264 WORKSHOP

CMP264 seeks to change the Transport and Tariff Model and billing arrangements to remove the netting of output from New Embedded Generators until Ofgem has completed its consideration of the current electricity transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented.

## Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP264 Embedded Generation Triad Avoidance Standstill** tabled by Scottish Power at the Modifications Panel meeting on 27 May 2016.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

   **Use of System Charging Methodology**

   (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

   (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

   (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;

   (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.).

   (e)Promoting efficiency in the implementation and administration of the system charging methodology

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

## Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

   a) The Workgroup should consider whether, on the balance of probabilities, the current level of embedded generation triad avoidance benefit significantly exceeds the actual avoided transmission investment cost, whether this causes a distortion in competition, and whether the proposed temporary removal of such benefits (pending the outcome and implementation of Ofgem's considerations) would better meet the code objectives.
   b) The Workgroup should not attempt to resolve the issue of what the most appropriate charging arrangements should be on an enduring basis, as this will be the subject of Ofgem's considerations. .
   c) The Workgroup should consider the definition of and criteria for the "disapplication date" in the proposed solution, i.e. the date on which the modification would cease to have effect.
   d) The Workgroup should consider whether the Workgroup's conclusions would be materially impacted by the length of time between implementation and the "disapplication date".
   e) The Workgroup should consider consumer impacts resulting from the proposal.
   f) Consider any link to the Balancing and Settlement Code with particular focus on timescales of any changes.
   g) Consider any link to EMR Settlements metering with particular focus on timescales of any changes.

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

9. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **15 working days** as determined by the Modifications Panel.

11. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **20 October 2016** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **23 November 2016**.

## Membership

13. It is recommended that the Workgroup has the following members:

| Role | Name | Representing |
|---|---|---|
| Chairman | Louise Schmitz | National Grid |
| National Grid Representative | Paul Wakeley/Rob Marshall | National Grid |
| Industry Representatives | Rupert Steele<br><br>James Anderson<br>Paul Mott<br>John Tindal<br>Andy Pace<br>Sam Wither<br>Christopher Granby<br>Bill Reed<br>Lars Weber<br>Michael Davis<br>Joe Underwood<br>Simon Lord | Scottish Power (Proposer)<br><br>Scottish Power<br>EDF<br>SSE<br>Cornwall Energy<br>UK Power Reserve<br>Infinis<br>RWE Supply & Trading<br>Neas Energy<br>Eider Reserve Power<br>Drax Power<br>Engie |

| | | |
|---|---|---|
| | Tim Collins<br>Lisa Waters<br>Graz McDonald<br>Jonathan Graham<br>Stephen Davies<br>Matthew Tucker<br>Mark Draper<br>Guy Phillips<br>John Harmer<br>Fruzina Kemenes<br><br>Kirsten Gardner | Centrica<br>Waters Wye<br>Greenfrog Power<br>The ADE<br>EON<br>Welsh Power<br>Peakgen<br>Uniper<br>Alkane<br>Innogy Renewables & Npower<br>Stag Energy |
| Authority Representatives | Donald Smith/Dena Barasi/Dominic Green | OFGEM |
| Technical secretary | Caroline Wright | National Grid |
| Observers | Kate Dooley<br>Nick Rubin/Talia Addy/John Lucas<br>Bruno Menu<br>Depak Lal | Energy UK<br>ELEXON<br><br>Lime Jump<br>AMP Plc |

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP264 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal;
- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

16. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has

been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

17. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

18. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

19. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

## Appendix 1

Proposed CMP264 Revised Timetable

| | |
|---|---|
| 17 May 2016 | CUSC Modification Proposal submitted |
| 27 May 2016 | CUSC Modification tabled at Panel meeting |
| 31 May 2016 | Request for Workgroup members (5 Working days) |
| 14 June 2016 | Workgroup meeting 1 |
| 21 June 2016 | Workgroup meeting 2 |
| 4 July 2016 | Workgroup meeting 3 |
| 11 July 2016 | Workgroup Meeting 4 |
| 27 July 2016 | Workgroup Meeting 5 (teleconference) |
| ~~18 July 2016~~<br>29 July 2016 | Workgroup Consultation issued ~~(15 Working days)~~ (17 Working Days) |
| 11 August 2016 | Workgroup meeting 6 |
| ~~8 August 2016~~<br>24 August 2016 | Deadline for responses |
| 30 August 2016 | Workgroup meeting 7 **(WG review Consultation Reponses)** |
| ~~15 or 16 August 2016~~<br>1 September 2016 | Workgroup meeting 8 (WG to agree options for WACMs) |
| 7 September 2016 | Workgroup meeting 9 (WG cont. of WACM options) |
| 12 September 2016 | Workgroup meeting 10 (WG cont. of WACM options) |
| 19 September 2016 | Workgroup meeting 11 (WG WACM vote) |
| 5 October 2016 | Workgroup meeting 12 (WG vote) |
| ~~18 August 2016~~<br>~~22 September 2016~~<br>20 October 2016 | Workgroup report issued to CUSC Panel |
| ~~26 August 2016~~<br>~~30 September 2016~~<br>25 October 2016 | Special CUSC Panel meeting to discuss Workgroup Report |

| | |
|---|---|
| ~~30 August 2016~~<br>~~3 October 2016~~<br>25 October 2016 | Code Administrator Consultation issued (~~10~~ 8 Working days) |
| ~~13 September 2016~~<br>~~17 October 2016~~<br>4 November 2016 | Deadline for responses |

| | |
|---|---|
| ~~15 September 2016~~<br>~~20 October 2016~~<br>10 November 2016 | Draft FMR published for industry comment (~~5~~ 2 Working days) |
| ~~22 September 2016~~<br>~~24 October 2016~~<br>15 November 2016 | Deadline for comments |
| ~~23 September 2016~~<br>~~20 October 2016~~<br>17 November 2016 | Draft FMR circulated to Panel |
| ~~30 September 2016~~<br>~~28 October 2016~~<br>23 November 2016 | Special CUSC Panel Recommendation vote |
| ~~5 October 2016~~<br>~~1 November 2016~~<br>23 November 2016 | FMR circulated for Panel comment (~~3~~2 Working days) |
| ~~10 October 2016~~<br>~~3 November 2016~~<br>25 November 2016 | Deadline for Panel comment |
| ~~12 October 2016~~<br>~~4 November 2016~~<br>28 November 2016 | Final report sent to Authority for decision |
| ~~26 October 2016~~<br>~~18 November 2016~~<br>12 December 2016 | Indicative Authority Decision due (10 Working days) |
| 2 November 2016<br>~~25 November 2016~~<br>19 December 2016 | Implementation date (5 Working days later) |

# Workgroup Terms of Reference and Membership

## TERMS OF REFERENCE FOR CMP265 WORKSHOP

CMP265 seeks to address the issue that half hourly metered (HH) demand for TNUoS purposes is currently charged net of embedded generation.

## Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP265 'Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market'** tabled by EDF Energy at the Modifications Panel meeting on 27 May 2016.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

   **Use of System Charging Methodology**

   (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;

   (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection);

   (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses.

   - (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.).

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC Modification provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

## Scope of work

4. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

a) This Workgroup should not focus on transmissions generator in negative zones.
b) The Workgroup should not look to amend the existing Capacity Mechanism.
c) The Workgroup should consider all Embedded Generation with Capacity Market contracts directly or indirectly.
d) The Workgroup should consider consumer impacts resulting from the proposal.
e) The Workgroup should consider whether, on the balance of probabilities, the current level of embedded generation triad avoidance benefit significantly exceeds the actual avoided transmission investment cost, whether this causes a distortion in competition, and whether the removal of such benefits (pending the outcome and implementation of Ofgem's considerations) would better meet the code objectives.
f) Consider any link to the Balancing and Settlement Code with particular focus on timescales of any changes.
g) Consider any link to EMR Settlements metering with particular focus on timescales of any changes.

6. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

7. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

8. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

9. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **15 working days** as determined by the Modifications Panel.

11. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **20 October 2016** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **23 November 2016**.

## Membership

13. It is recommended that the Workgroup has the following members

| Role | Name | Representing |
|---|---|---|
| Chairman | Louise Schmitz | National Grid |
| National Grid Representative | Paul Wakeley/Rob Marshall | National Grid |
| Industry Representatives | Rupert Steele | Scottish Power (Proposer) |
| | James Anderson | Scottish Power |
| | Paul Mott | EDF |
| | John Tindal | SSE |
| | Andy Pace | Cornwall Energy |
| | Sam Wither | UK Power Reserve |
| | Christopher Granby | Infinis |
| | Bill Reed | RWE Supply & Trading |
| | Lars Weber | Neas Energy |
| | Michael Davis | Eider Reserve Power |
| | Joe Underwood | Drax Power |
| | Simon Lord | Engie |
| | Tim Collins | Centrica |
| | Lisa Waters | Waters Wye |
| | Graz McDonald | Greenfrog Power |
| | Jonathan Graham | The ADE |
| | Stephen Davies | EON |
| | Matthew Tucker | Welsh Power |
| | Mark Draper | Peakgen |
| | Guy Phillips | Uniper |

| | | |
|---|---|---|
| | John Harmer<br>Fruzina Kemenes<br><br>Kirsten Gardner | Alkane<br>Innogy Renewables & Npower<br>Stag Energy |
| Authority Representatives | Donald Smith/Dena Barasi/Dominic Green | OFGEM |
| Technical secretary | Caroline Wright | National Grid |
| Observers | Kate Dooley<br>Nick Rubin/Talia Addy/John Lucas<br>Bruno Menu<br>Depak Lal | Energy UK<br>ELEXON<br><br>Lime Jump<br>AMP Plc |

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP265 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

15. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal*;*
- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

16. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

17. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

18. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

19. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

## Appendix 1

Proposed CMP265 Revised Timetable

| | |
|---|---|
| 17 May 2016 | CUSC Modification Proposal submitted |
| 27 May 2016 | CUSC Modification tabled at Panel meeting |
| 31 May 2016 | Request for Workgroup members (5 Working days) |
| 14 June 2016 | Workgroup meeting 1 |
| 21 June 2016 | Workgroup meeting 2 |
| 4 July 2016 | Workgroup meeting 3 |
| 11 July 2016 | Workgroup Meeting 4 |
| 27 July 2016 | Workgroup Meeting 5 (teleconference) |
| ~~18 July 2016~~<br>29 July 2016 | Workgroup Consultation issued ~~(15 Working days)~~ (17 Working Days) |
| 11 August 2016 | Workgroup meeting 6 |
| ~~8 August 2016~~<br>24 August 2016 | Deadline for responses |
| 30 August 2016 | Workgroup meeting 7 **(WG review Consultation Reponses)** |
| ~~15 or 16 August 2016~~<br>1 September 2016 | Workgroup meeting 8 (WG to agree options for WACMs) |
| 7 September 2016 | Workgroup meeting 9 (WG cont. of WACM options) |
| 12 September 2016 | Workgroup meeting 10 (WG cont. of WACM options) |
| 19 September 2016 | Workgroup meeting 11 (WG WACM vote) |
| 5 October 2016 | Workgroup meeting 12 (WG vote) |
| ~~18 August 2016~~<br>~~22 September 2016~~<br>20 October 2016 | Workgroup report issued to CUSC Panel |
| ~~26 August 2016~~<br>~~30 September 2016~~<br>25 October 2016 | Special CUSC Panel meeting to discuss Workgroup Report |

| | |
|---|---|
| ~~30 August 2016~~<br>~~3 October 2016~~<br>25 October 2016 | Code Administrator Consultation issued (~~10~~ 8 Working days) |
| ~~13 September 2016~~<br>~~17 October 2016~~<br>4 November 2016 | Deadline for responses |
| ~~15 September 2016~~<br>~~20 October 2016~~ | Draft FMR published for industry comment (~~5~~ 2 Working days) |

| | |
|---|---|
| 10 November 2016 | |
| ~~22 September 2016~~<br>~~24 October 2016~~<br>15 November 2016 | Deadline for comments |
| ~~23 September 2016~~<br>~~20 October 2016~~<br>17 November 2016 | Draft FMR circulated to Panel |
| ~~30 September 2016~~<br>~~28 October 2016~~<br>23 November 2016 | Special CUSC Panel Recommendation vote |
| ~~5 October 2016~~<br>~~1 November 2016~~<br>23 November 2016 | FMR circulated for Panel comment (~~3~~2 Working days) |
| ~~10 October 2016~~<br>~~3 November 2016~~<br>25 November 2016 | Deadline for Panel comment |
| ~~12 October 2016~~<br>~~4 November 2016~~<br>28 November 2016 | Final report sent to Authority for decision |
| ~~26 October 2016~~<br>~~18 November 2016~~<br>12 December 2016 | Indicative Authority Decision due (10 Working days) |
| 2 November 2016<br>~~25 November 2016~~<br>19 December 2016 | Implementation date (5 Working days later) |

# Workgroup Terms of Reference and Membership

## TERMS OF REFERENCE FOR CMP 269 WORKSHOP

CMP269 aims for the CMP264 Workgroup to address a number of consequential changes required to non-charging sections of the CUSC to reflect the CMP264 Proposal or any alternative proposals agreed by the CMP264 Workgroup.

## Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP269 'Potential consequential changes to the CUSC as a result of CMP264'** tabled by Scottish Power at the Modifications Panel meeting on 26 August 2016.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

**Standard CUSC Objectives**

(a) The efficient discharge by the Licensee of the obligations imposed on it by the Act and the Transmission Licence;

(b) Facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity;

(c) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

## Scope of work

3. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

4. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

a)
b)
c)

5. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

6. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

7. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

8. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

9. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **XX working days** as determined by the Modifications Panel.

10. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

11. The Workgroup is to submit its final report to the Modifications Panel Secretary on **xx xxx 2016** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **xx xxx 2016**

## Membership

12. It is recommended that the Workgroup has the same membership as CMP264.

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

13. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP269 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

14. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

    - Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
    - Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal*;*
    - Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

    The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

15. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

16. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

17. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

18. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

## Appendix 1

| | |
|---|---|
| 1 September 2016 | Workgroup meeting 8 (WG to agree options for WACMs) |
| 7 September 2016 | Workgroup meeting 9 (WG cont. of WACM options) |
| 12 September 2016 | Workgroup meeting 10 (WG cont. of WACM options) |
| 19 September 2016 | Workgroup meeting 11 (WG WACM vote) |
| 5 October 2016 | Workgroup meeting 12 (WG vote) |
| 20 October 2016 | Workgroup report issued to CUSC Panel |
| 25 October 2016 | Special CUSC Panel meeting to discuss Workgroup Report |

| | |
|---|---|
| 25 October 2016 | Code Administrator Consultation issued (~~10~~ 8 Working days) |
| 4 November 2016 | Deadline for responses |
| 10 November 2016 | Draft FMR published for industry comment (~~5~~ 2 Working days) |
| 15 November 2016 | Deadline for comments |
| 17 November 2016 | Draft FMR circulated to Panel |
| 23 November 2016 | Special CUSC Panel Recommendation vote |
| 23 November 2016 | FMR circulated for Panel comment (~~3~~2 Working days) |
| 25 November 2016 | Deadline for Panel comment |
| 28 November 2016 | Final report sent to Authority for decision |
| 12 December 2016 | Indicative Authority Decision due (10 Working days) |
| 19 December 2016 | Implementation date (5 Working days later) |

# Workgroup Terms of Reference and Membership

## TERMS OF REFERENCE FOR CMP 270 WORKSHOP

CMP270 aims for the CMP265 Workgroup to address a number of consequential changes required to non-charging sections of the CUSC to reflect the CMP265 Proposal or any alternative proposals agreed by the CMP265 Workgroup.

## Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP270 'Potential consequential changes to the CUSC as a result of CMP265'** tabled by EDF Energy at the Modifications Panel meeting on 26 August 2016.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the Applicable CUSC Objectives. These can be summarised as follows:

**Standard CUSC Objectives**

(a) The efficient discharge by the Licensee of the obligations imposed on it by the Act and the Transmission Licence;

(b) Facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity;

(c) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.

## Scope of work

3. The Workgroup must consider the issues raised by the Modification Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

4. In addition to the overriding requirement of paragraph 4, the Workgroup shall consider and report on the following specific issues:

a)
b)
c)

5. The Workgroup is responsible for the formulation and evaluation of any Workgroup Alternative CUSC Modifications (WACMs) arising from Group discussions which would, as compared with the Modification Proposal or the current version of the CUSC, better facilitate achieving the Applicable CUSC Objectives in relation to the issue or defect identified.

6. The Workgroup should become conversant with the definition of Workgroup Alternative CUSC Modification which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual member of the Workgroup to put forward a WACM if the member(s) genuinely believes the WACM would better facilitate the achievement of the Applicable CUSC Objectives, as compared with the Modification Proposal or the current version of the CUSC. The extent of the support for the Modification Proposal or any WACM arising from the Workgroup's discussions should be clearly described in the final Workgroup Report to the CUSC Modifications Panel.

7. Workgroup members should be mindful of efficiency and propose the fewest number of WACMs possible.

8. All proposed WACMs should include the Proposer(s)'s details within the final Workgroup report, for the avoidance of doubt this includes WACMs which are proposed by the entire Workgroup or subset of members.

9. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **xx working days** as determined by the Modifications Panel.

10. Following the Consultation period the Workgroup is required to consider all responses including any WG Consultation Alternative Requests. In undertaking an assessment of any WG Consultation Alternative Request, the Workgroup should consider whether it better facilitates the Applicable CUSC Objectives than the current version of the CUSC.

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

11. The Workgroup is to submit its final report to the Modifications Panel Secretary on **xx xxx 2016** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **xx xxx 2016**.

## Membership

12. It is recommended that the Workgroup has the following members as CMP265.

NB: A Workgroup must comprise at least 5 members (who may be Panel Members). The roles identified with an asterisk in the table above contribute toward the required quorum, determined in accordance with paragraph 14 below.

13. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP270 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

14. A vote is to take place by all eligible Workgroup members on the Modification Proposal and each WACM. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference). The Workgroup chairman shall not have a vote, casting or otherwise]. There may be up to three rounds of voting, as follows:

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal*;*
- Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

The results from the vote and the reasons for such voting shall be recorded in the Workgroup report in as much detail as practicable.

15. It is expected that Workgroup members would only abstain from voting under limited circumstances, for example where a member feels that a proposal has been insufficiently developed. Where a member has such concerns, they should raise these with the Workgroup chairman at the earliest possible opportunity and certainly before the Workgroup vote takes place. Where abstention occurs, the reason should be recorded in the Workgroup report.

16. Workgroup members or their appointed alternate are required to attend a minimum of 50% of the Workgroup meetings to be eligible to participate in the Workgroup vote.

17. The Technical Secretary shall keep an Attendance Record for the Workgroup meetings and circulate the Attendance Record with the Action Notes after each meeting. This will be attached to the final Workgroup report.

18. The Workgroup membership can be amended from time to time by the CUSC Modifications Panel.

## Appendix 1

| | |
|---|---|
| 1 September 2016 | Workgroup meeting 8 (WG to agree options for WACMs) |
| 7 September 2016 | Workgroup meeting 9 (WG cont. of WACM options) |
| 12 September 2016 | Workgroup meeting 10 (WG cont. of WACM options) |
| 19 September 2016 | Workgroup meeting 11 (WG WACM vote) |
| 5 October 2016 | Workgroup meeting 12 (WG vote) |
| 20 October 2016 | Workgroup report issued to CUSC Panel |
| 25 October 2016 | Special CUSC Panel meeting to discuss Workgroup Report |

| | |
|---|---|
| 25 October 2016 | Code Administrator Consultation issued (~~10~~ 8 Working days) |
| 4 November 2016 | Deadline for responses |
| 10 November 2016 | Draft FMR published for industry comment (~~5~~ 2 Working days) |
| 15 November 2016 | Deadline for comments |
| 17 November 2016 | Draft FMR circulated to Panel |
| 23 November 2016 | Special CUSC Panel Recommendation vote |
| 23 November 2016 | FMR circulated for Panel comment (~~3~~2 Working days) |
| 25 November 2016 | Deadline for Panel comment |
| 28 November 2016 | Final report sent to Authority for decision |
| 12 December 2016 | Indicative Authority Decision due (10 Working days) |
| 19 December 2016 | Implementation date (5 Working days later) |

## Annex 3– Workgroup attendance register

A – Attended
X – Absent
O – Alternate
D – Dial-in

| Name | Organisation | Role | 13/06/16 CMP265 14/06/16 CMP264 | 21/06/16 | 04/07/16 | 11/07/16 | 28/07/16 (t-conf) | 11/8/16 | 30/8/16 | 1/9/16 | 7/9/16 | 12/9/16 | 15/9/16 | 19/9/16 | 5/10/16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Louise Schmitz | National Grid | Chair | A | A | A | A | AD | A | A | A | A | A | A | X | A |
| John Martin | National Grid | Chair (alternate) | X | X | X | X | X | X | X | X | X | X | X | A | X |
| Ryan Place | National Grid | Technical Secretary | A | X | X | X | X | X | X | X | X | X | X | X | X |
| Caroline Wright | National Grid | Technical Secretary | A | A | A | X | A | A | A | A | A | A | A | A | A |
| Heena Chauhan | National Grid | Technical Secretary | X | X | X | A | X | X | X | X | X | X | X | X | X |
| Paul Wakeley | National Grid | National Grid Rep | A | A | A | A | A | A | A | A | X | X | X | X | X |
| Rob Marshall | National Grid | National Grid Rep | X | X | X | X | X | X | A | A | A | A | A | A | A |
| John Harmer | Alkane | Workgroup member | A | AD | A | A | AD | A | A | A | A | A | A | A | A |
| Tim Collins | Centrica | Workgroup member | X | A | A | A | AD | A | A | A | A | A/D | A | A | A |

| Name | Organisation | Role | 13/06/16 CMP265 14/06/16 CMP264 | 21/06/16 | 04/07/16 | 11/07/16 | 28/07/16 (t-conf) | 11/8/16 | 30/8/16 | 1/9/16 | 7/9/16 | 12/9/16 | 15/9/16 | 19/9/16 | 5/10/16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| George Moran | Centrica | Workgroup alternate | X | X | X | X | X | X | X | X | X | X | X | X | X |
| Andy Pace | Cornwall Energy | Workgroup member | A | A | X | A | AD | A | X | A | A/D | A/D | A | A | A/D |
| Tim Dixon | Cornwall Energy | Workgroup alternate | X | X | AO | X | X | X | X | X | X | X | X | X | X |
| Tom Edwards | Cornwall Energy | Workgroup alternate | X | X | X | X | X | X | A | X | X | X | X | X | X |
| Joseph Underwood | Drax Power | Workgroup member | A | A | A | A | AD | A | A | A | X | X | X | X | A |
| Paul Mott | EDF Energy | CMP265 Proposer | X | A | A | A | AD | A | A | A | A | A | A | A | A |
| Mark Cox | EDF Energy | Workgroup alternate | AO | X | X | X | X | X | X | X | X | X | X | X | X |
| Natasha Ranatunga | EDF Energy | Workgroup alternate | AD | X | X | X | X | X | X | X | X | X | X | X | X |
| Michael Davies | Eider Reserve Power | Workgroup member | A | A | A | AD | X | A | A | A | A | A | A | A | X |
| Nicholas Rubin | ELEXON | Observer | X | X | A | A | AD | A | A | A/D | X | X | A/D | X | X |
| John Lucas | ELEXON | Observer | X | A | X | X | X | X | X | X | A | X | X | X | X |
| Talia Addy | ELEXON | Observer | X | A | X | X | X | X | X | X | X | X | X | X | X |
| Kate Dooley | Energy UK | Observer | AD | X | AD | X | X | X | X | X | X | X | X | X | X |
| Simon Lord | Engie | Workgroup member | A | A | A | A | A | A | A | A | A | A | A | A | A |

| Name | Organisation | Role | 13/06/16 CMP265 14/06/16 CMP264 | 21/06/16 | 04/07/16 | 11/07/16 | 28/07/16 (t-conf) | 11/8/16 | 30/8/16 | 1/9/16 | 7/9/16 | 12/9/16 | 15/9/16 | 19/9/16 | 5/10/16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Stephen Davies | EON | Workgroup member | A | X | A | X | X | X | A | A | A | X | X | A | X |
| Laurence Barrett | EON | Workgroup alternate | X | X | X | X | X | A | X | X | X | A | A | A | A |
| Brian Tilley | EON | Workgroup alternate | X | X | X | AO | X | X | X | X | X | X | X | X | X |
| Graz MacDonald | Greenfrog Power | Workgroup member | A | A | A | AD | AD | X | A | A | A | A/D | A/D | A/D | X |
| Mark Jones | Greenfrog Power | Workgroup alternate | X | X | X | X | X | X | X | X | X | A | A | X | X |
| Jeremy Taylor | Greenfrog Power | Workgroup alternate | X | X | X | X | X | X | X | X | X | X | X | A | A |
| Christopher Granby | Infinis | Workgroup member | A | A | X | A | X | X | X | X | X | A | X | A | A |
| Anthony Collet | Infinis | Workgroup alternate | X | X | X | X | X | X | X | A | X | X | X | X | X |
| Jon Crouch | Infinis | Workgroup alternate | X | X | X | X | X | X | X | X | A/D | X | X | X | X |
| Mick Collister | Infinis | Workgroup alternate | X | X | X | X | X | X | A | X | X | X | X | X | X |
| Lucas Lilja | Intergen | Observer | X | AD | X | X | AD | X | X | X | X | X | X | X | X |
| Bruno Menu | Lime Jump | Observer | X | X | X | X | X | X | X | X | X | X | X | X | X |
| Lars Weber | NEAS Energy | Workgroup member | A | A | A | A | X | A | A | A/D | X | X | X | X | X |

| Name | Organisation | Role | 13/06/16 CMP265 14/06/16 CMP264 | 21/06/16 | 04/07/16 | 11/07/16 | 28/07/16 (t-conf) | 11/8/16 | 30/8/16 | 1/9/16 | 7/9/16 | 12/9/16 | 15/9/16 | 19/9/16 | 5/10/16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dominic Green | Ofgem | Observer | AD | A | A | X | AD | X | A | A | A | A | X | A | A |
| Dena Barasi | Ofgem | Observer | X | X | X | X | X | A | X | X | A | X | A/D | X | X |
| Jon Fairchild | Peakgen | Workgroup alternate | A | X | X | X | X | X | X | X | X | X | X | X | X |
| Mark Draper | Peakgen | Workgroup Member | X | AO | AO | AO | AD | A | A | X | X | X | X | X | X |
| Nick Stillito | Peakgen | Workgroup alternate | X | X | X | X | X | X | X | A | A | A | A | A | A |
| Bill Reed | RWE Supply and Trading | Workgroup member | A | A | A | A | AD | A | A | A | A | A | A | A | A |
| Fruzina Kemenes | Innogy Renewables and npower | Workgroup member | X | AO | AO | X | AD | A | A | X | X | A/D | A | A | A |
| Herdial Dosanjh | Npower | Workgroup alternate | X | X | X | X | X | X | X | A | X | X | X | X | X |
| George Douthwaite | RWE Npower | Workgroup alternate | X | X | X | AO | AD | X | X | X | A/D | A | X | X | X |
| James Anderson | Scottish Power | Workgroup member | X | A | A | X | AD | A | A | A | A | A | A | A | A |
| Richard Sweet | Scottish Power | Workgroup alternate | A | X | X | X | X | X | X | X | X | A | A | X | X |
| Rupert Steele | Scottish Power | CMP264 Proposer | AO | X | X | AO | X | A | X | X | X | X | X | X | X |

| Name | Organisation | Role | 13/06/16 CMP265 14/06/16 CMP264 | 21/06/16 | 04/07/16 | 11/07/16 | 28/07/16 (t-conf) | 11/8/16 | 30/8/16 | 1/9/16 | 7/9/16 | 12/9/16 | 15/9/16 | 19/9/16 | 5/10/16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| John Tindal | SSE | Workgroup member | A | A | A | X | AD | A | A | A | A | A | A | A | A |
| Gareth Graham | SSE | Workgroup alternate | X | X | X | AO | X | X | X | X | X | X | X | X | X |
| Kirsten Gardner | Stag Energy | Workgroup member | A | A | AD | A | AD | A | A/D | A/D | A | A/D | A/D | A | X |
| Adam Heffill | Stag Energy | Workgroup alternate | X | X | X | X | X | X | X | X | X | X | X | X | A |
| Jonathan Graham | The ADE | Workgroup member | A | X | A | A | AD | A | A | A | A | A | A | A | A |
| Tim Rotheray | The ADE | Workgroup alternate | X | AO | X | X | X | X | X | X | X | X | X | X | X |
| Sam Wither | UK Power Reserve | Workgroup member | A | X | X | A | AD | A | A/D | A | A | A | A | A | A |
| Ian Tanner | UK Power Reserve | Workgroup alternate | AO | A/D | A/D | AD | AD | X | X | X | X | X | X | X | X |
| Guy Phillips | Uniper | Workgroup member | A | A | A | AD | X | A | X | X | X | A | X | X | X |
| Paul Jones | Uniper | Workgroup alternate | X | X | X | X | AD | X | A | A | A | A | A/D | A | A |
| Lisa Waters | Waters Wye | Workgroup member | A | A | A | X | X | A | A | A | A | X | A/D | X | A |
| Matthew Tucker | Welsh Power | Workgroup member | A | A | A | A | X | A | A | A | A | A | A | A | A |

# Annex 4 – Draft legal text changes

# CMP264 Original

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node’s marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

### Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

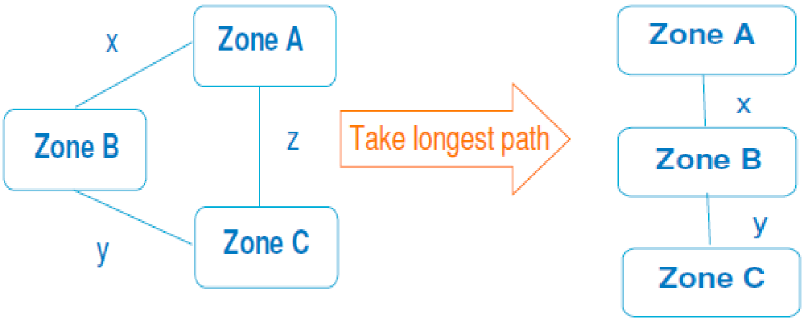
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

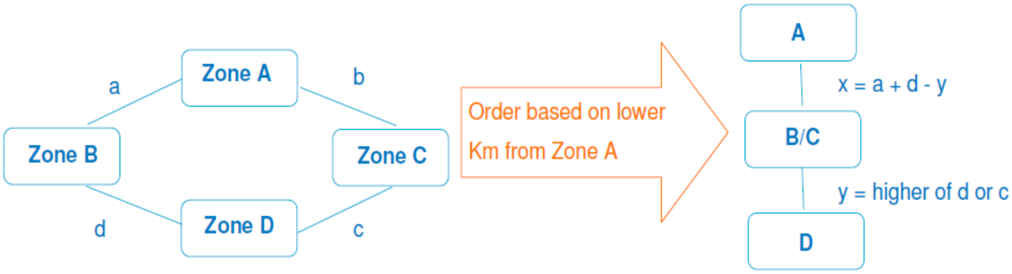
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

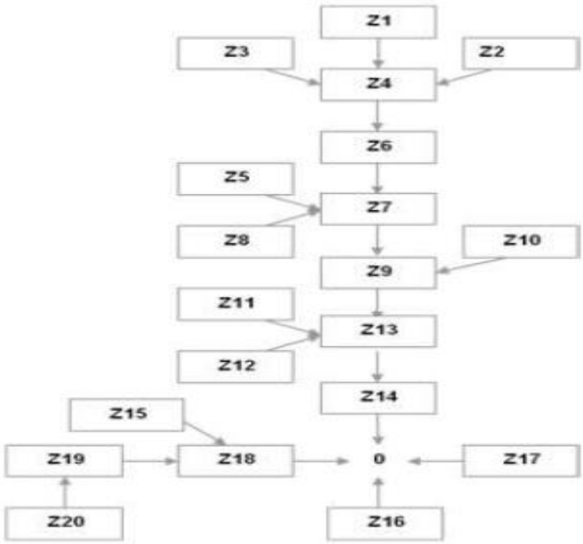
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_k} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$

$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$

$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$ = Peak Security Zonal Marginal km for each demand zone

$ZMkm_{DiYR}$ = Year Round Zonal Marginal km for each demand zone

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each demand one

$ITT_{DiYR}$ = Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$ITRR_D$ = Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts).

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS and where all or part of the associated generation has certification in accordance with Engineering Recommendation G59 (or a relevant replacement of G59 certification) after 30/06/2017.
G59 certification requirements are published by The Energy Networks Association.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

| | | |
|---|---|---|
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff for the demand zone; |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff for the demand zone, and |
| EX | = | £0 |

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

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| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}\left(EET_{Di} \times EEV_{Di}\right)$$

Where

| | |
|---|---|
| $ITTR_{EE}$ | = Initial Revenue impact for Embedded Exports |
| $EEV_{Di}$ | = Forecast Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |



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14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the

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relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a

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number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$ and $$FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$



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For $i$=z+1 to 14: $$RFT_{Di} = FT_{Di} + NRRT_D$$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} *100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

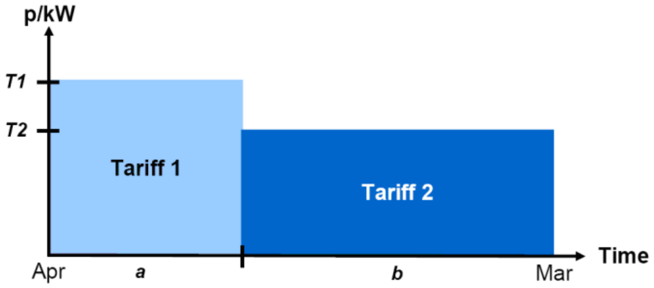
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

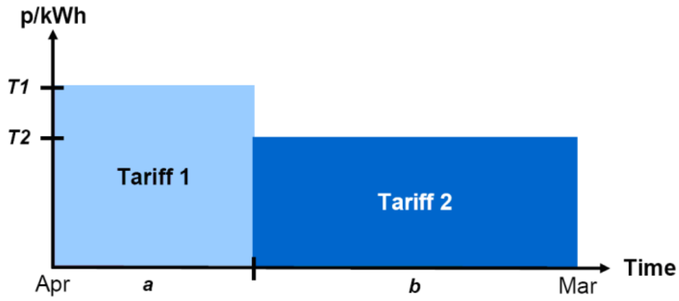
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

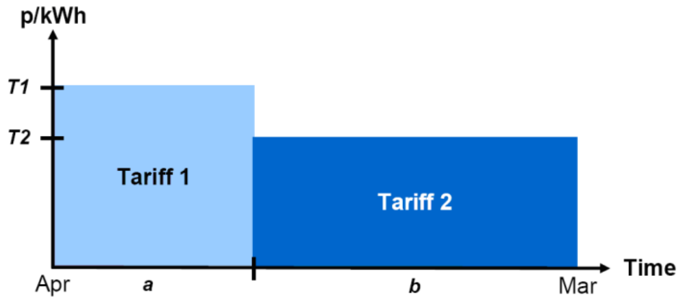
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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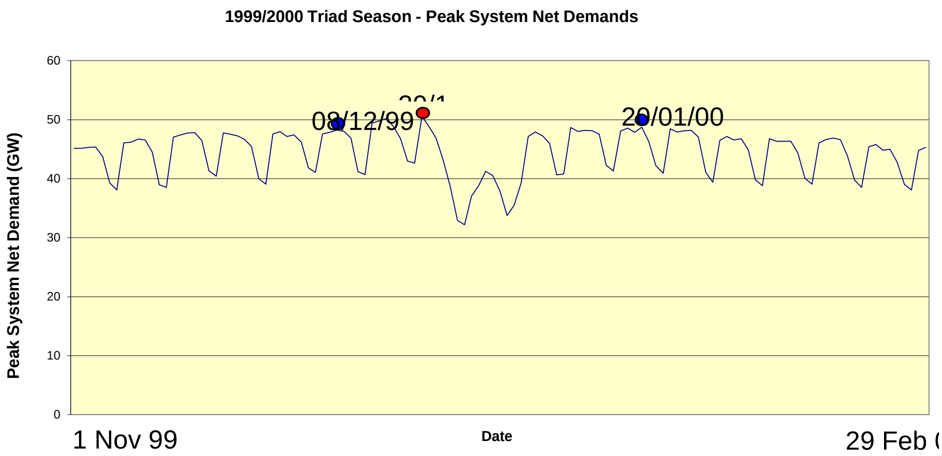


### Half-hourly metered demand charges

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

### Monthly Charges

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} \times £10.07/\text{MWkm} \times 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \underline{\mathbf{£3.45/kW}}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

$= (9{,}000kW - 7{,}200kW) \times$ £10.00/kW

$= 1{,}800kW \times$ £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

$= (-500kW - -600kW) \times$ £5.00/kW

$= 100kW \times$ £5.00/kW

**= £500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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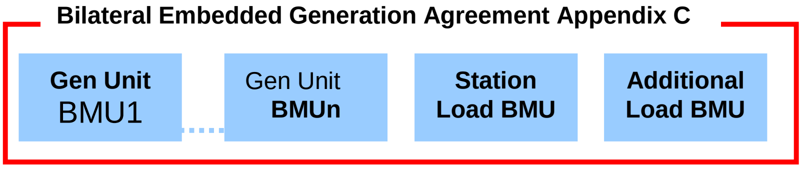
| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
|  | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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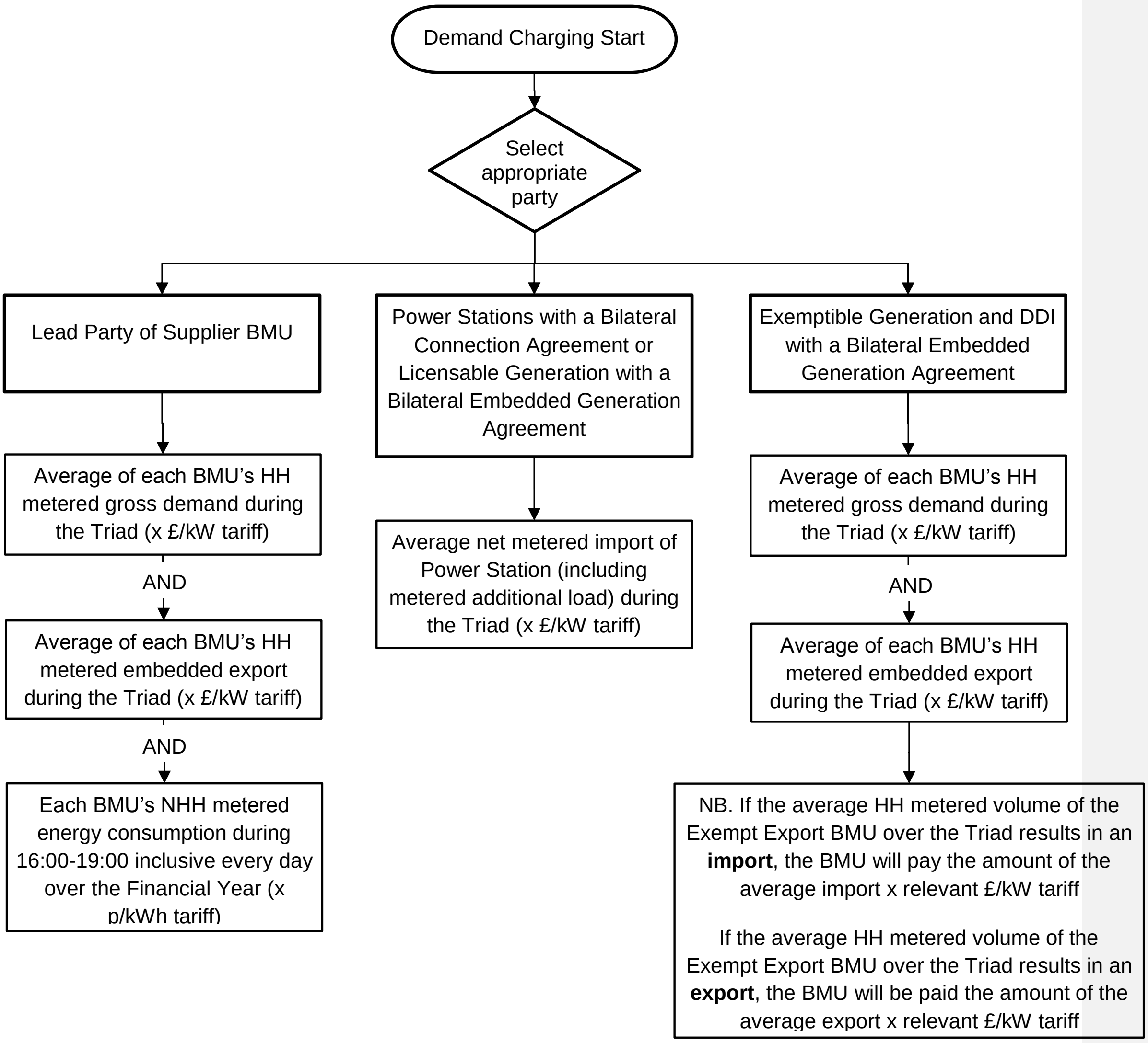
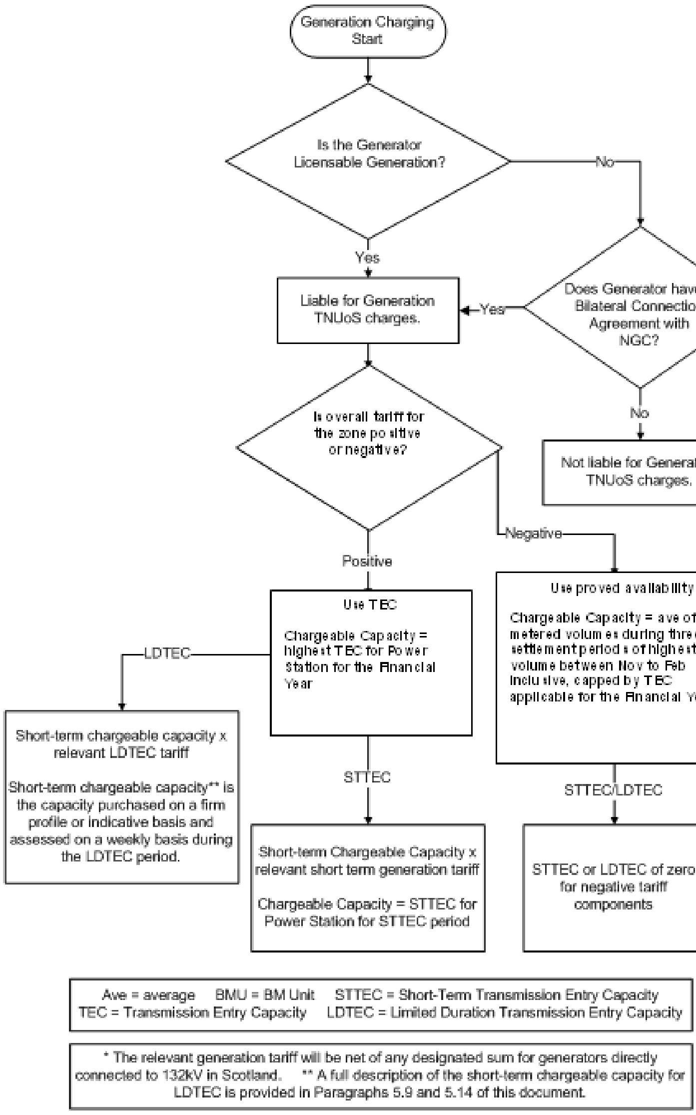



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

## Generation Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

$F = T$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

$F = T * D/P$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

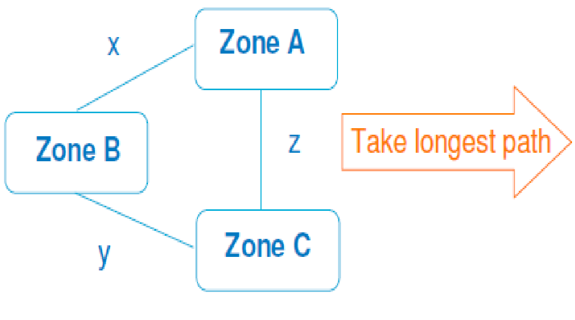
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

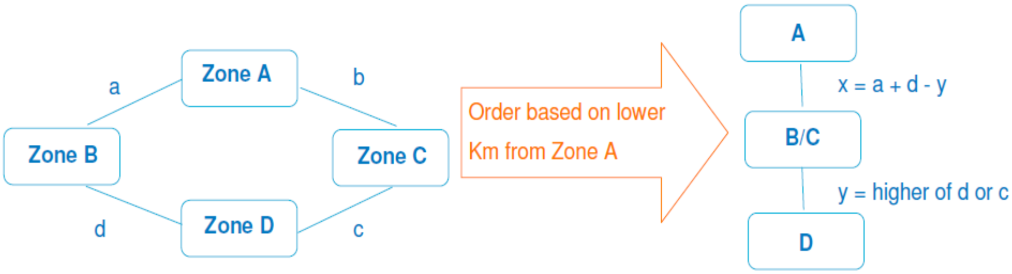
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

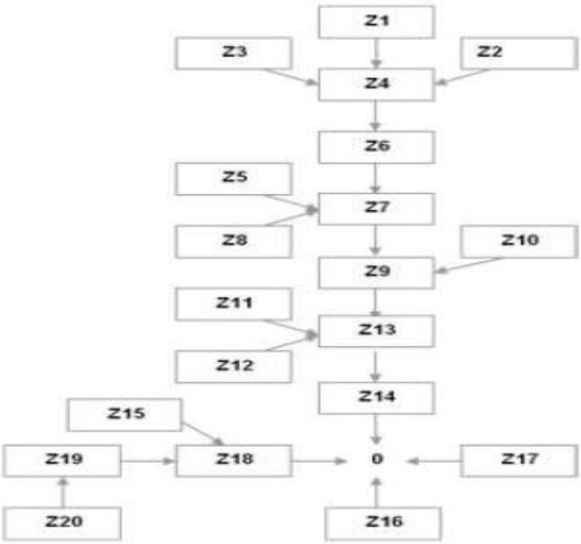
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| **400kV OHL expansion constant calculation** | **Ave £/MWkm** |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = $RT_G \times -1$

Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\;L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

| | | |
|---|---|---|
| $ELT_{Gi}$ | = | Effective Local Tariff (£/kW) |
| $SLT_{Gi}$ | = | Substation Local Tariff (£/kW) |

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$

Where

$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for

FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $LCRR_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the

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relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a

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number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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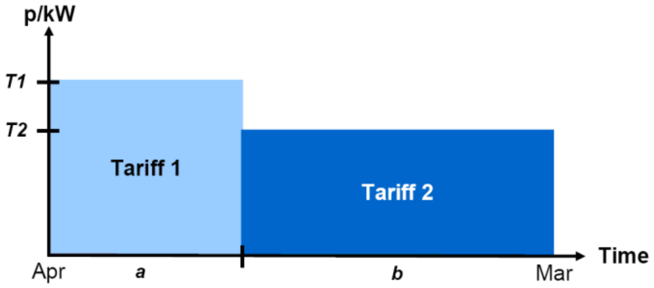
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ \ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ \ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

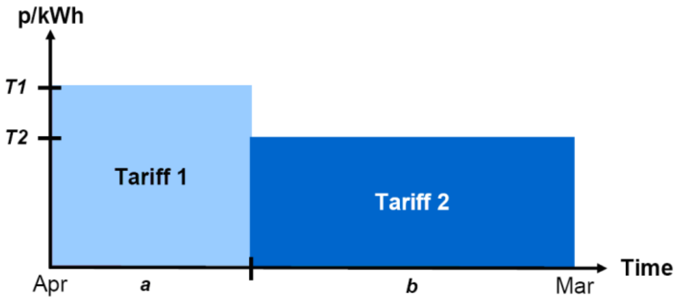
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$\mathit{Annual\ Liability}_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times \mathit{Tariff}\ 1) + (b \times \mathit{Tariff}\ 2)}{12}\right)$$

Deleted: $\mathit{Annual\ Liability}_{D}$

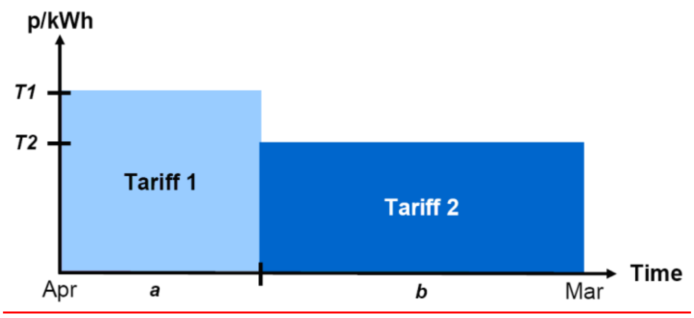
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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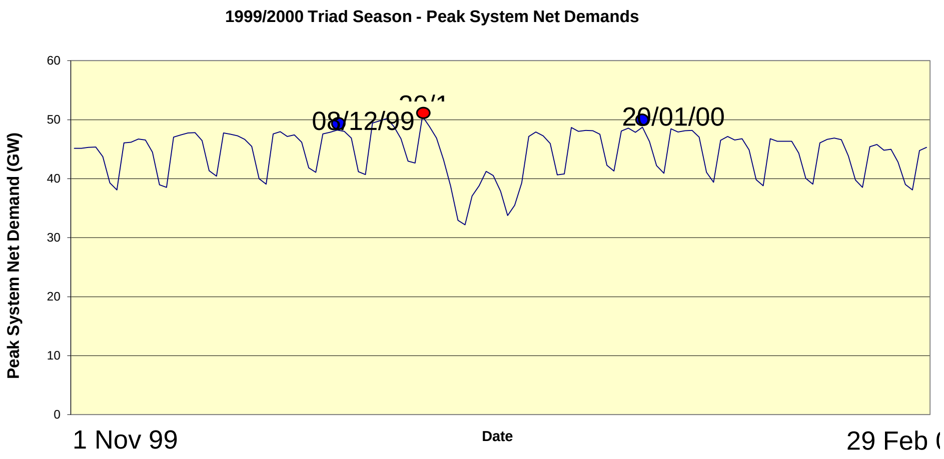


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

= $\frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

= $\frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} - 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**

**Supplier Use of System Agreement**

**Supplier** BMU1 ····· Supplier **BMUn**

| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

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**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**

**Bilateral Connection Agreement Appendix C**

**Gen Unit** BMU1 ····· Gen Unit **BMUn** | **Station Load BMU** | **Additional Load BMU**

| Demand Charges | Generation Charges |
|---|---|
| See **14.17.18.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges | Generation Charges |
| See **14.17.14, 14.17.15 and 14.17.18.** | See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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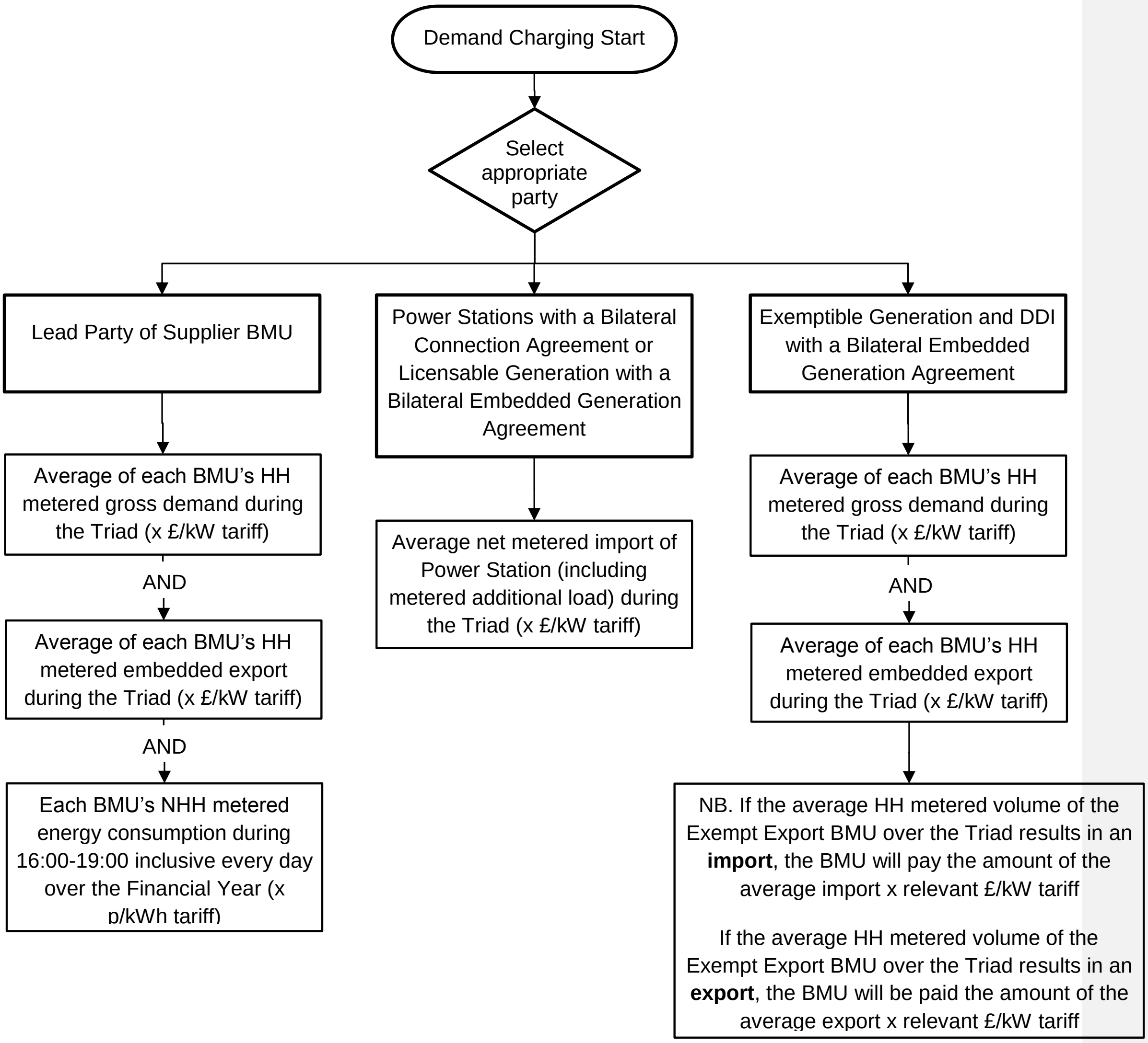
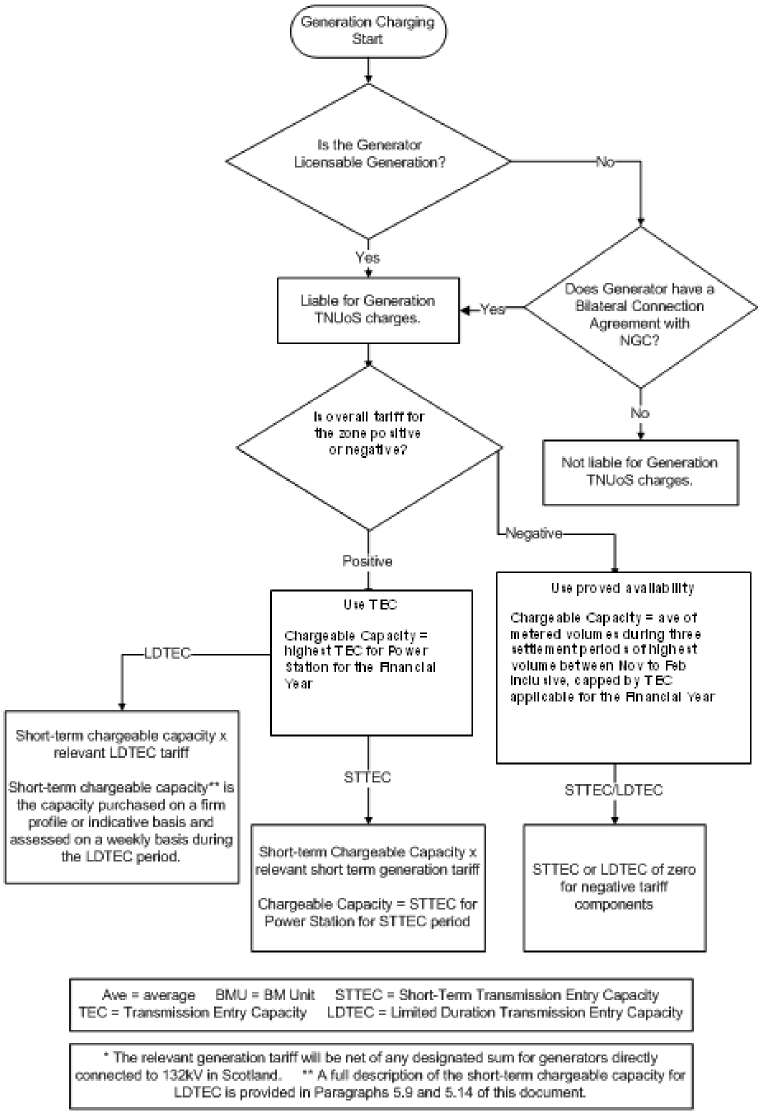



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

**Deleted:** h

where:

T = 10,000 kW (period November 2003 to February 2004)

**Deleted:** h

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

**Deleted:** h

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

**Deleted:** h

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP264 WACM2

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

## Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

### Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

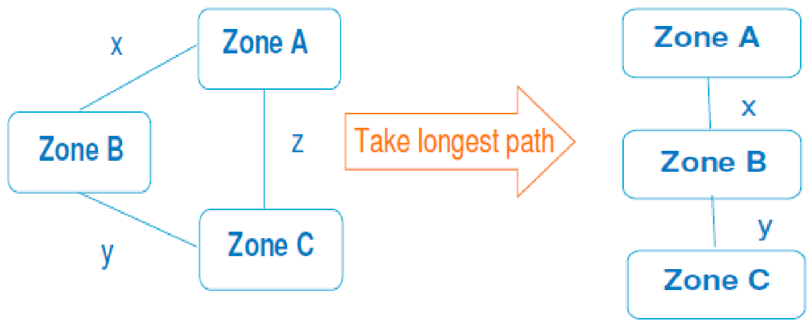
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

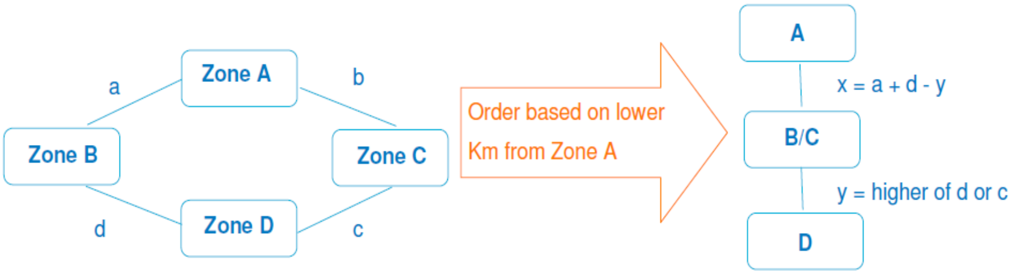
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

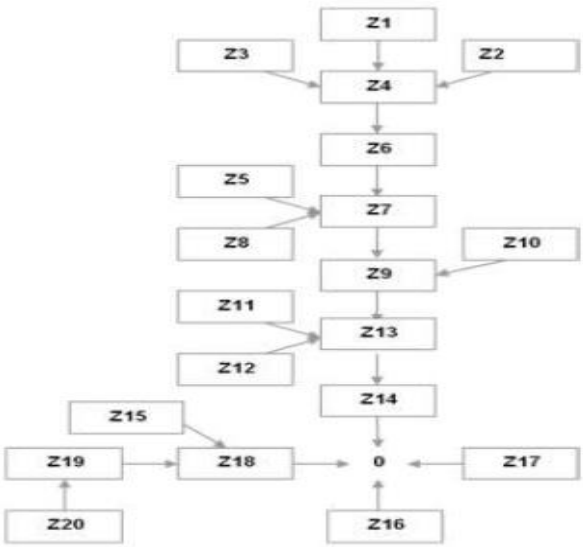
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| **400kV OHL expansion constant calculation** | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| **400kV OHL expansion constant calculation** | **Ave £/MWkm** |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$EX = \frac{2}{3}(XP - (RT_G \times -1)) + (RT_G \times -1)$$

Second charging year following the implementation date of CMP 264/265:

$$EX = \frac{2}{3}(XP - (RT_G \times -1)) + (RT_G \times -1)$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$EX = (RT_G \times -1)$$

Where
XP = Value of demand residual in charging year prior to implementation
$(RT_G \times -1)$ = Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiPS} \times D_{Di}) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ generation | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ generation | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14} (EET_{Di} \times EEV_{Di})$$

Where

| | | |
|---|---|---|
| $ITTR_{EE}$ | = | Initial Revenue impact for Embedded Exports |
| $EEV_{Di}$ (MW) | = | Forecast Embedded Export metered volume at Triad |

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

$$\sum_{k} \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

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14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

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14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\,offshore\\substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

| | | |
|---|---|---|
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$ and $$FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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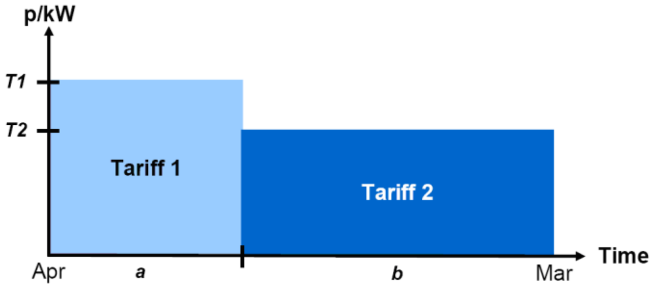
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

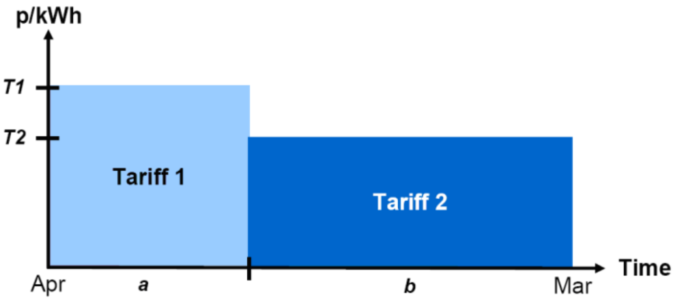
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

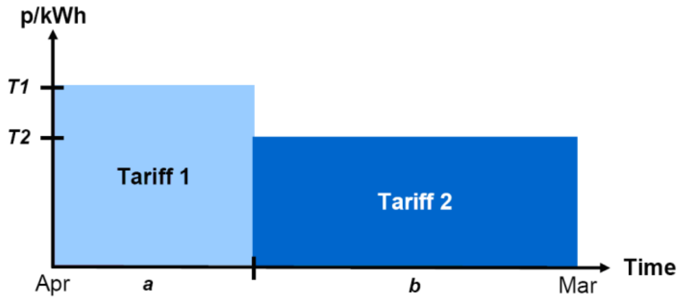
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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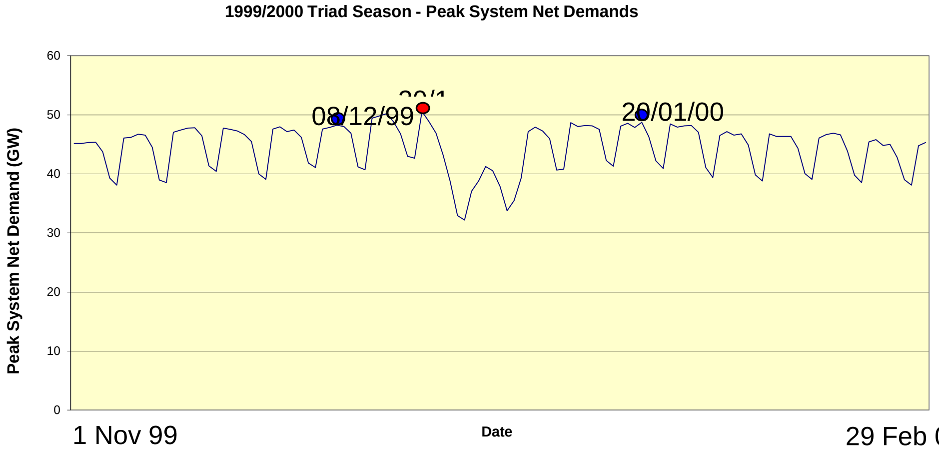


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company. **Deleted:** 18

## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation. **Deleted:** 19

### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges. **Deleted:** 20

### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad. **Deleted:** 1

14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months **Deleted:** 22

concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50,000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April $1^{st}$ to March $31^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April $1^{st}$ to March $31^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**

**Supplier Use of System Agreement**

| | |
|---|---|
| **Supplier** BMU1 | Supplier **BMUn** |

| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

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**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**

**Bilateral Connection Agreement Appendix C**

| | | | |
|---|---|---|---|
| **Gen Unit** BMU1 | Gen Unit **BMUn** | **Station Load BMU** | **Additional Load BMU** |

| Demand Charges | Generation Charges |
|---|---|
| See **14.17.18.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><td colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</td></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 ..... Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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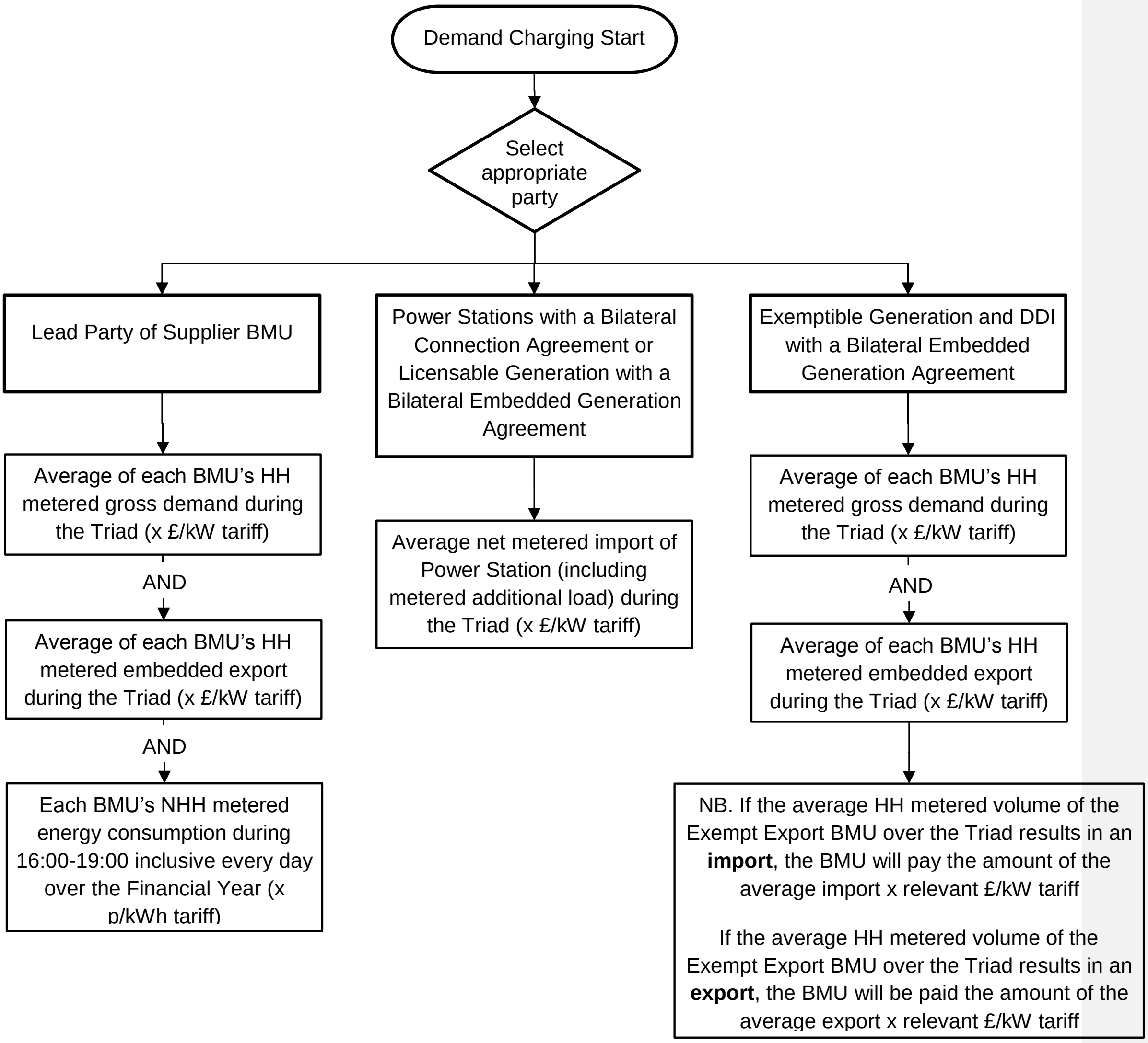
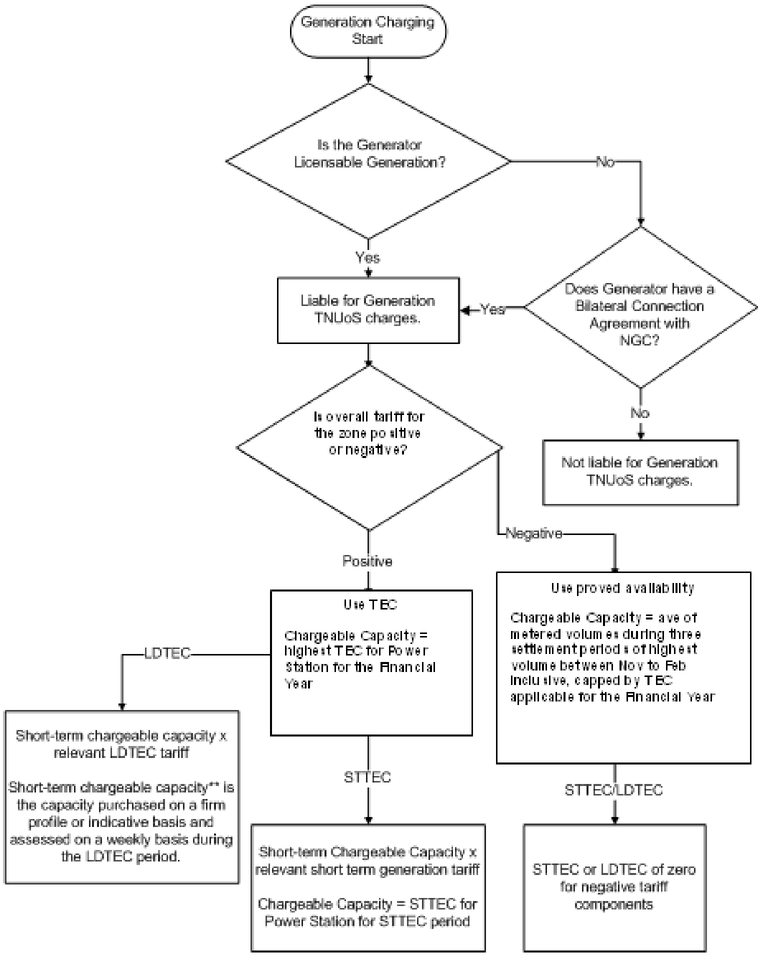



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

Generation
Charges




Ave = average    BMU = BM Unit    STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity    LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland.   ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

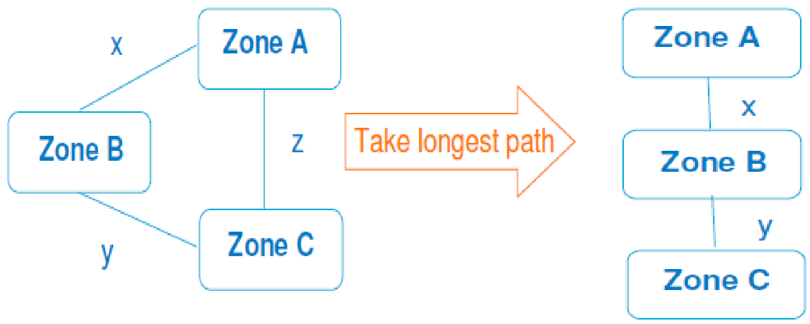
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

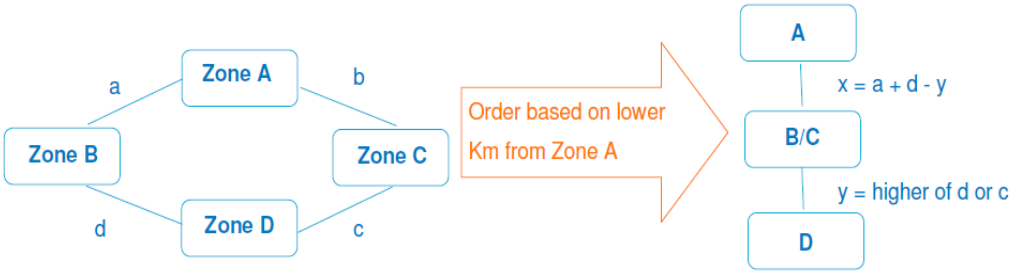
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

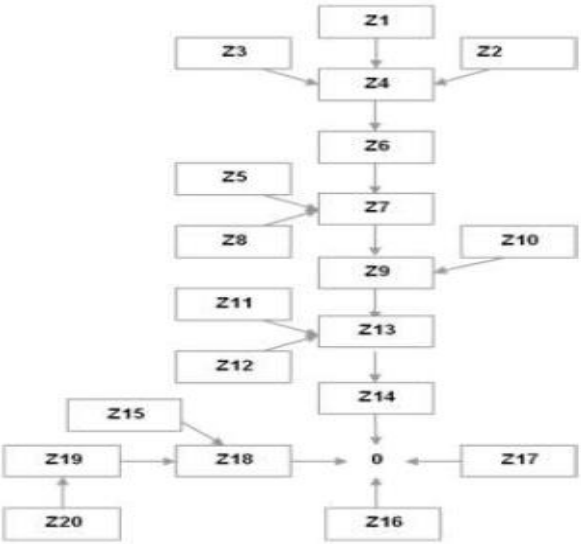
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

400kV underground cable factor: 22.39
275kV underground cable factor: 22.39
132kV underground cable factor: 27.79
400kV line factor: 1.00
275kV line factor: 1.14
132kV line factor: 2.24

Scottish Power & National Grid Regions

400kV underground cable factor: 22.39
275kV underground cable factor: 22.39
132kV underground cable factor: 30.22
400kV line factor: 1.00
275kV line factor: 1.14
132kV line factor: 2.80

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
| --- | --- |
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

## TNUoS Embedded Export Tariff

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.

The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

### Initial Revenue Recovery

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiPS} \times D_{Di}) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ generation | = | Year Round Not-Shared Initial Transport Revenue Recovery for |
| $ITRR_{GYRS}$ generation | = | Year Round Shared Initial Transport Revenue Recovery for |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ (MW) = Forecast Embedded Export metered volume at Triad

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under |

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$ and $$FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag

- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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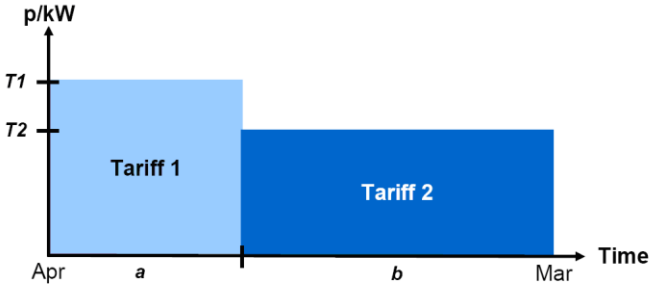
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

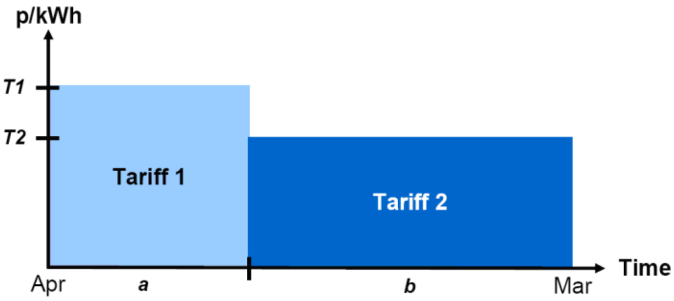
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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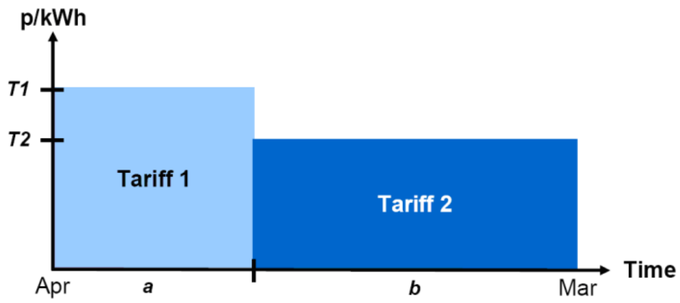
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.



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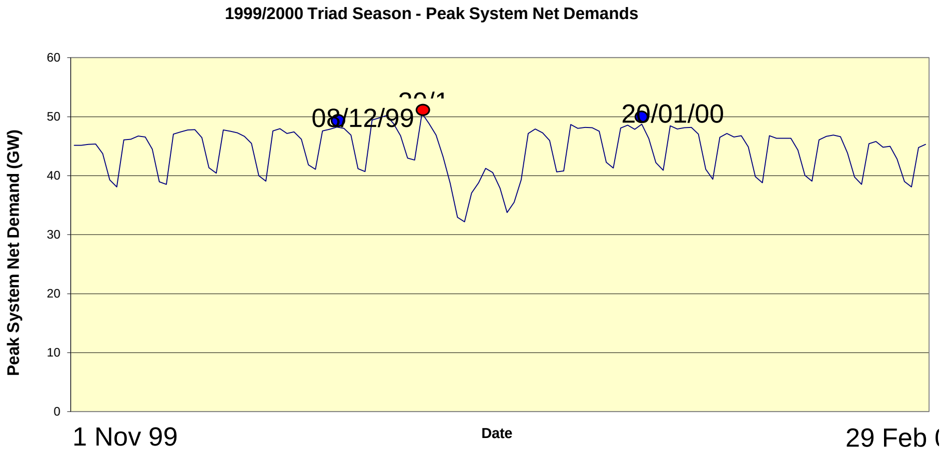


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

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14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**

1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

$= (9{,}000kW - 7{,}200kW) \times$ £10.00/kW

$= 1{,}800kW \times$ £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

$= (-500kW - -600kW) \times$ £5.00/kW

$= 100kW \times$ £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

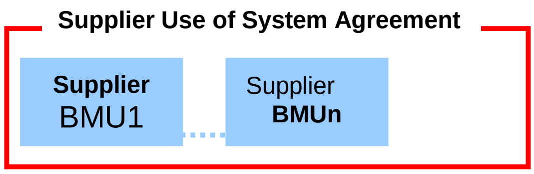
**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

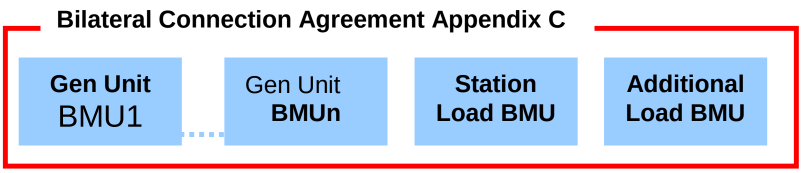
In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.18.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><th colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</th></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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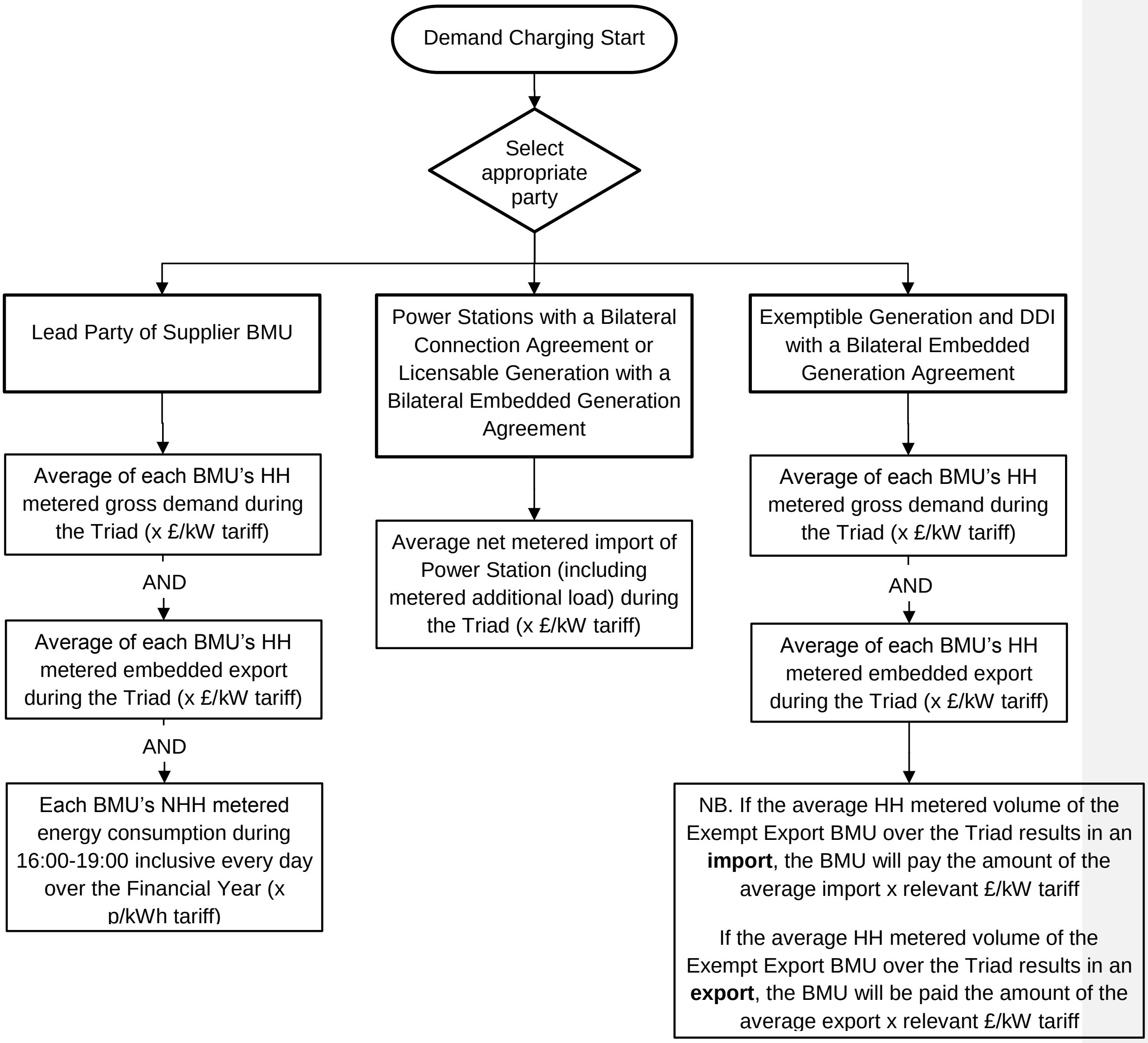
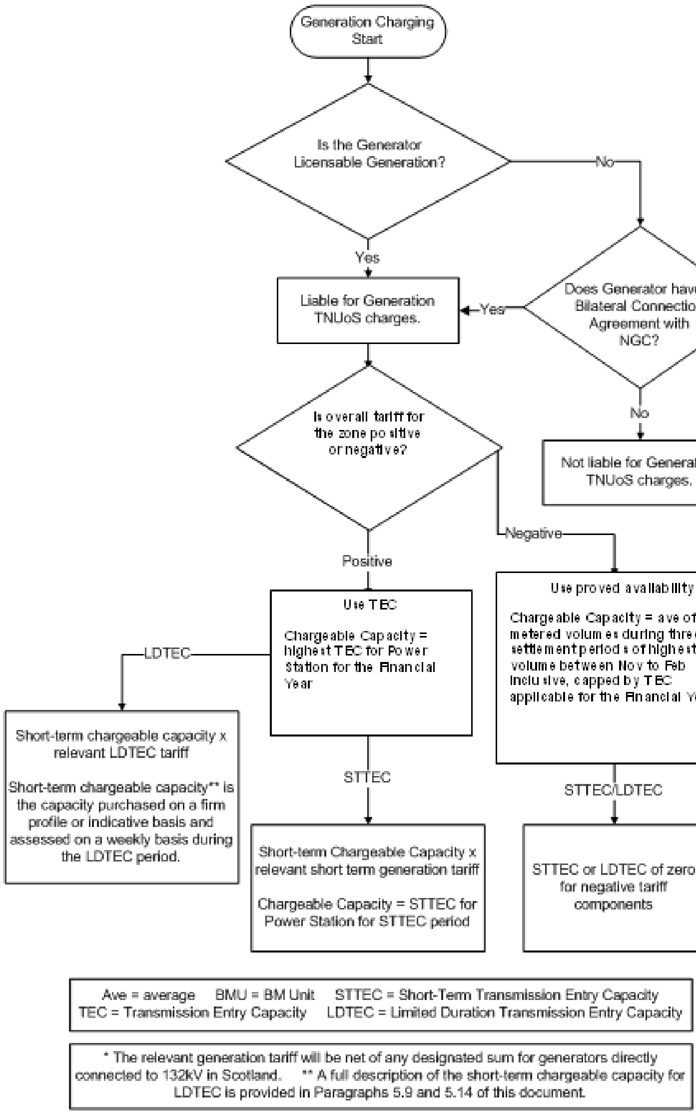



BMU = BM Unit    DDI = Derogated Distribution Interconnector
HH = Half hourly    NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP264 WACM4

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

### Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

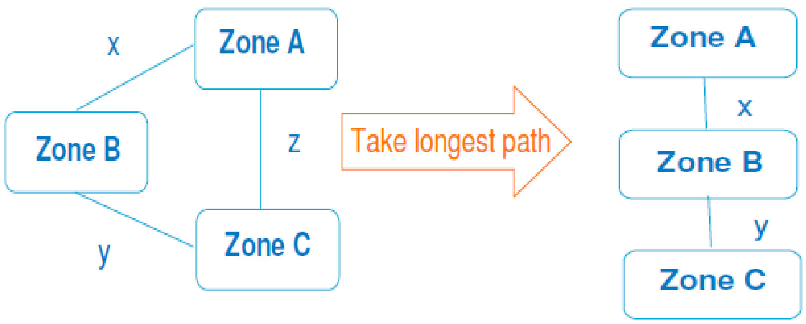
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

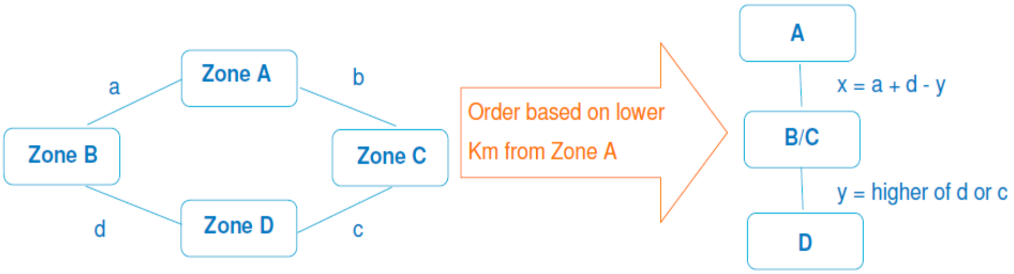
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

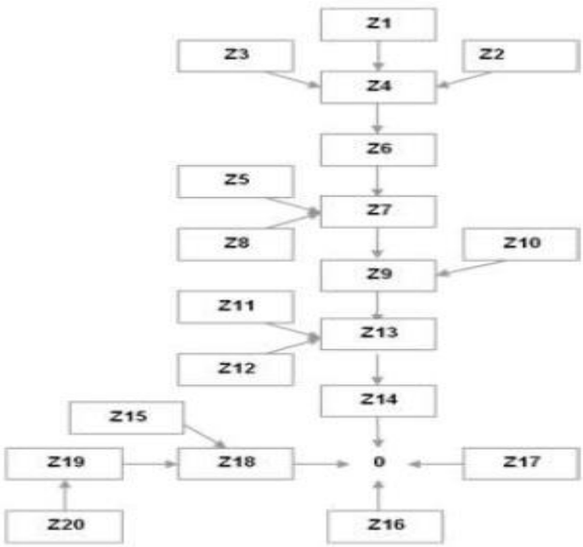
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| **400kV OHL expansion constant calculation** | **Ave £/MWkm** |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$ = Peak Security Zonal Marginal km for each demand zone

$ZMkm_{DiYR}$ = Year Round Zonal Marginal km for each demand zone

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each demand one

$ITT_{DiYR}$ = Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$ITRR_D$ = Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts).

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year “t” the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - AGIC) + AGIC$$

Second charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - AGIC) + AGIC$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$= AGIC$$

Where
XP = Value of demand residual in charging year prior to implementation
AGIC = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

Deleted: 113

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14} (EET_{Di} \times EEV_{Di})$$

Where

| | | |
|---|---|---|
| $ITTR_{EE}$ | = | Initial Revenue impact for Embedded Exports |
| $EEV_{Di}$ | = | Forecast Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
LCRR$_G$ = Local Charge Revenue Recovery
G$_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.132 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\,offshore\\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:
SLT$_k$ = the offshore substation tariff for substation k
Gen$_k$ = the generation connected to offshore substation k

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**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

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$$RT_D = \frac{(p \times TRR) - I}{}$$

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

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14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

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$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the

marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} *100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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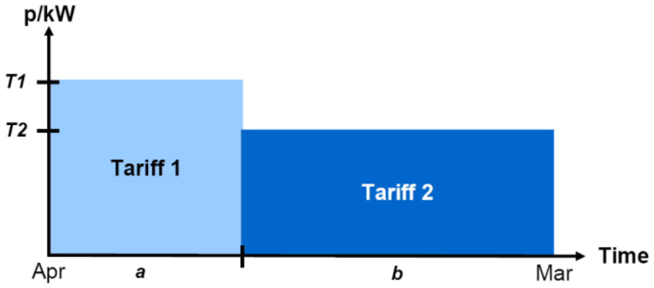
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

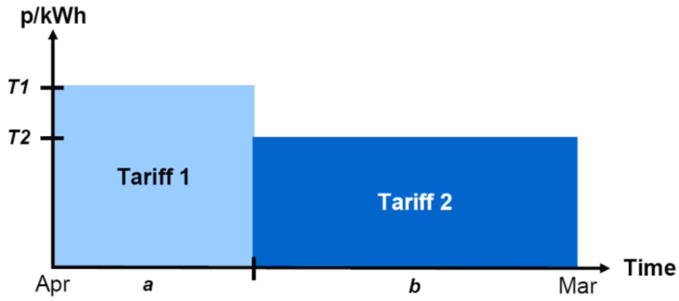
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

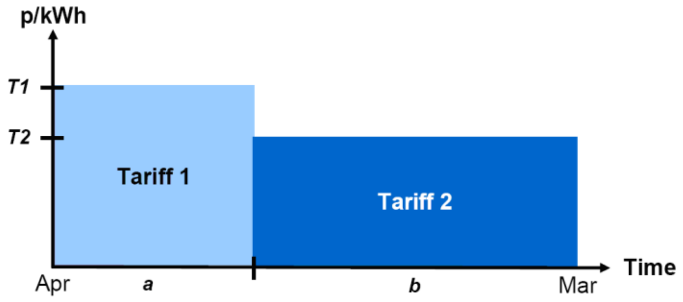
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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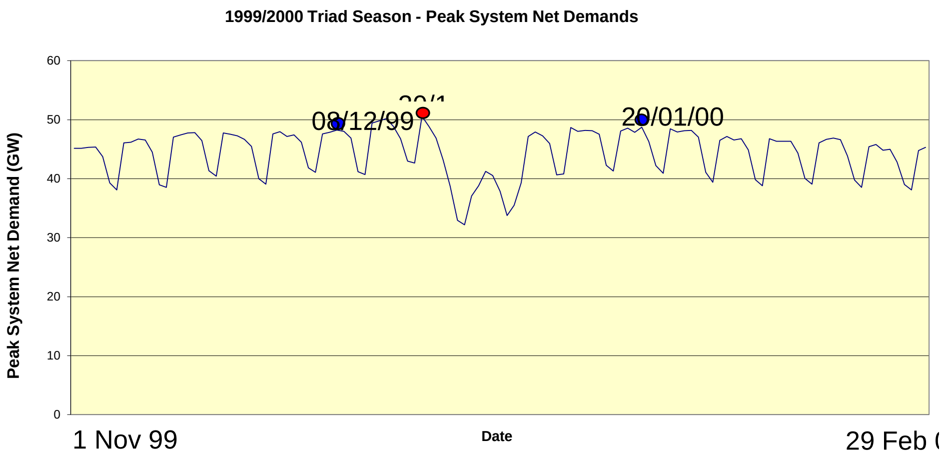


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:
- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50,000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

$= (9{,}000kW - 7{,}200kW) \times$ £10.00/kW

$= 1{,}800kW \times$ £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

$= (-500kW - -600kW) \times$ £5.00/kW

$= 100kW \times$ £5.00/kW

**= £500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**

**Supplier Use of System Agreement**

| **Supplier** BMU1 | Supplier **BMUn** |
|---|---|

| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

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**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**

**Bilateral Connection Agreement Appendix C**

| **Gen Unit** BMU1 | Gen Unit **BMUn** | **Station Load BMU** | **Additional Load BMU** |
|---|---|---|---|

| Demand Charges | Generation Charges |
|---|---|
| See **14.17.18.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><td colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</td></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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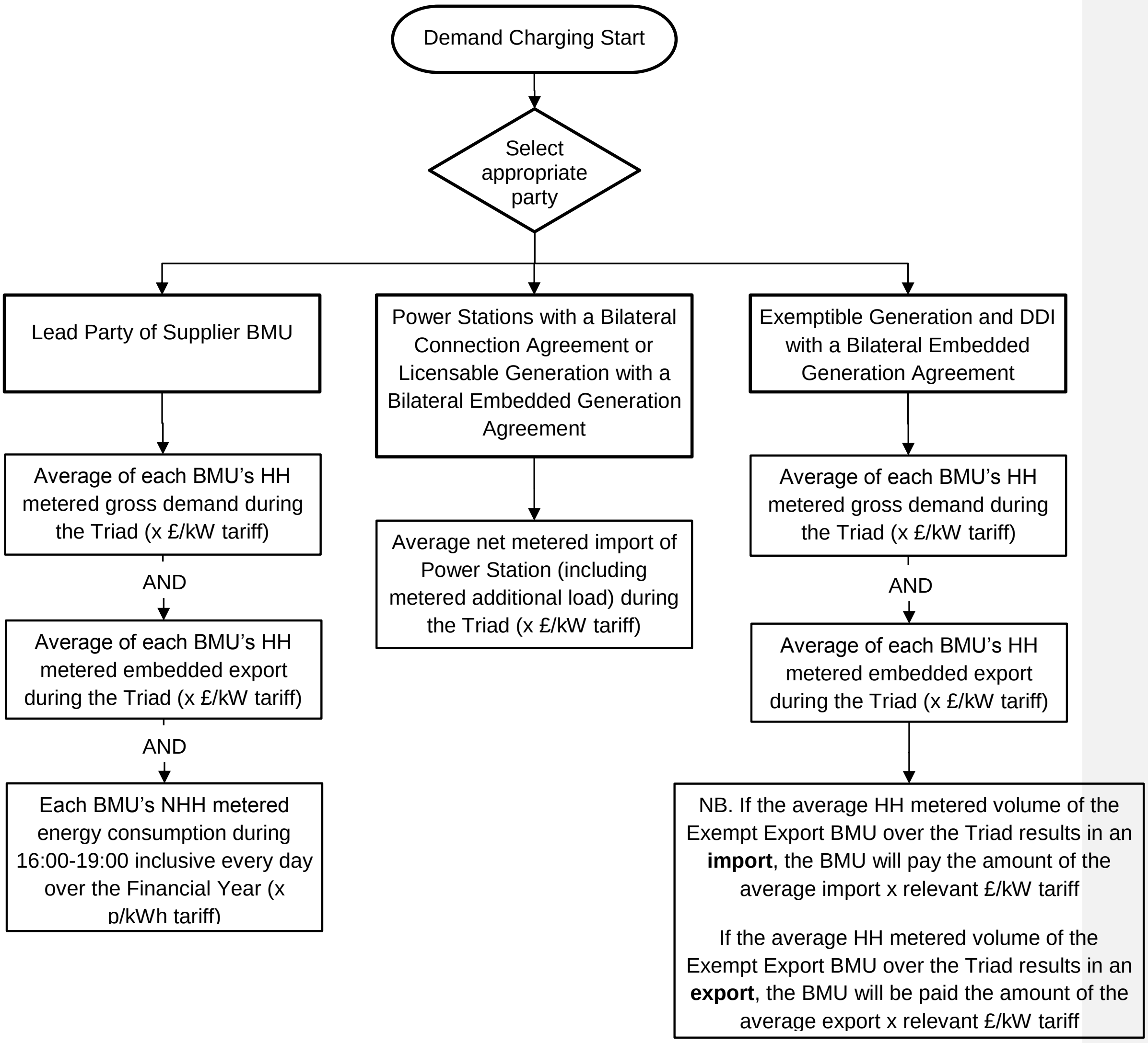
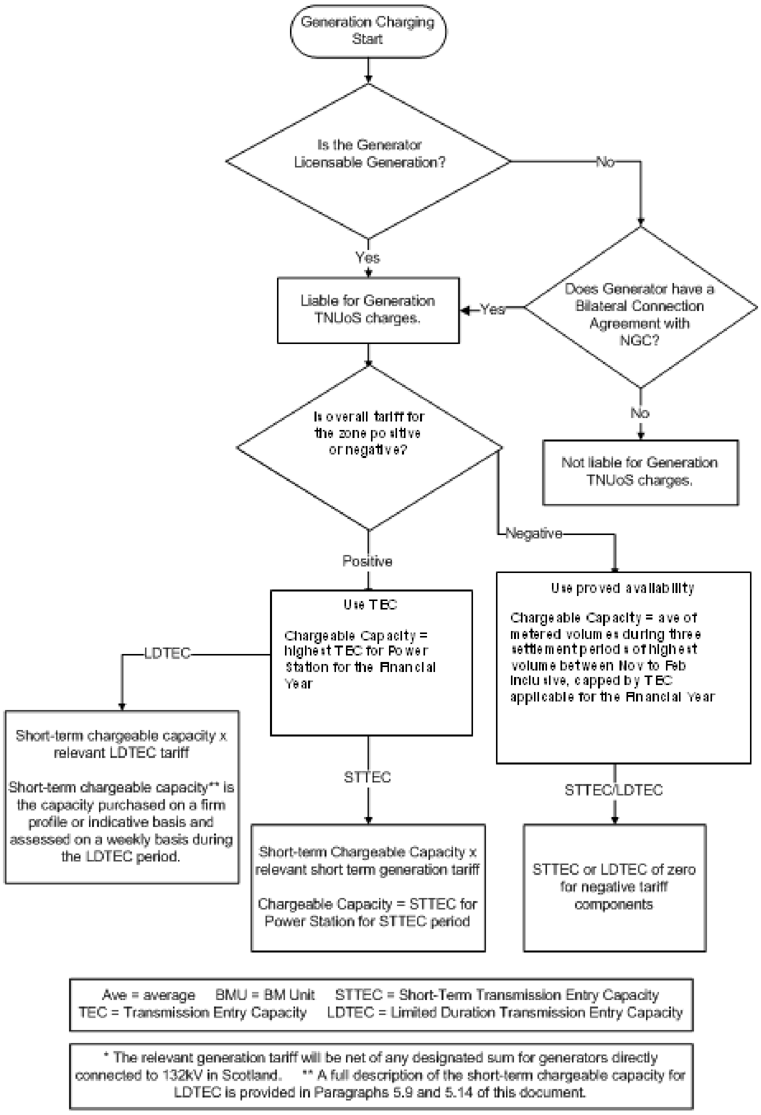



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Liable for Generation TNUoS charges.
Yes
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

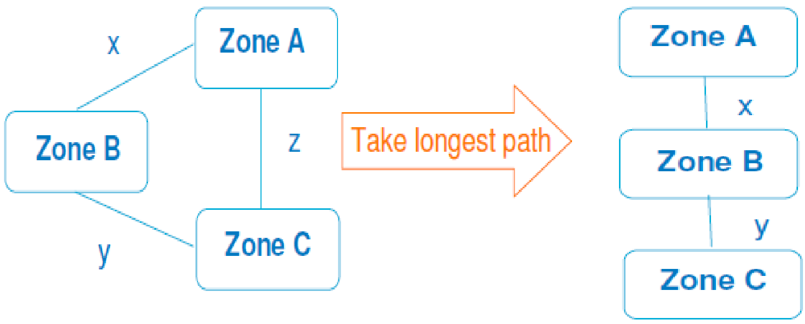
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

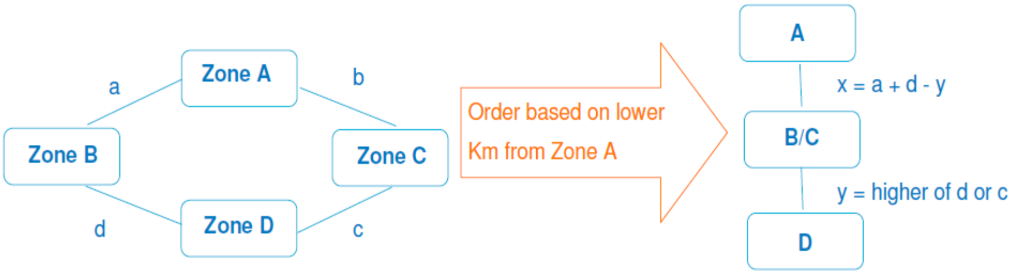
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

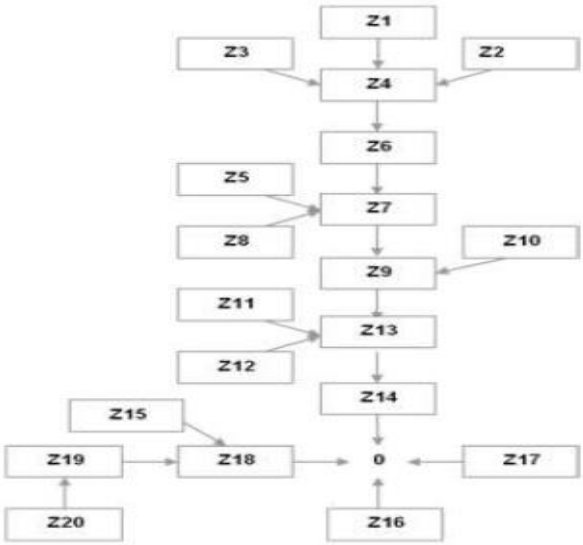
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:
i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$
$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TN

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ((RT_G \times -1) + AGIC)) + ((RT_G \times -1) + AGIC)$$

Second charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ((RT_G \times -1) + AGIC)) + ((RT_G \times -1) + AGIC)$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$= (RT_G \times -1) + AGIC$$

Where
XP = Value of demand residual in charging year prior to implementation
$RT_G$ = Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.
AGIC = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS}\times G_{Gi}\times F_{PS}\right)=ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type

n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS}\times D_{Di}\right)=ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS}\times G_{Gi}\times ALF\right)=ITRR_{G\,YRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

$$\sum_{k} \frac{NLMkm_{Gj}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

*k* = Local circuit *k* for generator

$NLMkm_{Gj}^{L}$ = Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor.

EC = Expansion Constant

$LocalSF_k$ = Local Security Factor for circuit *k*

$CLT_{Gi}$ = Circuit Local Tariff (£/kW)

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $\mathrm{LCRR}_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.132 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

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**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

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$$FT_{EEi} = \frac{12\times(ET_{EEi}\times\sum_{Di=1}^{14} EET_{Di}-FL_{Di})}{b\times\sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12\times\left(ET_{Di}\times\sum_{Di=1}^{14} D_{Di} - FL_{Di}\right)}{b\times\sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di}\times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.142 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the

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marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

## Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff} \quad \text{(£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

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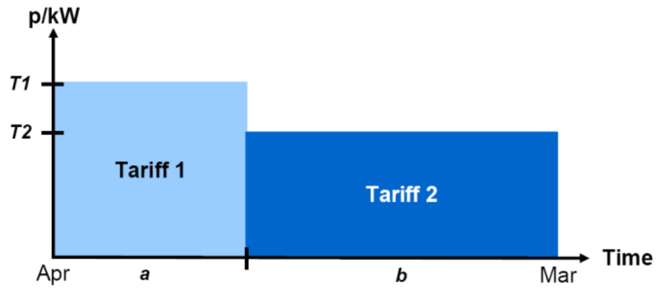



14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

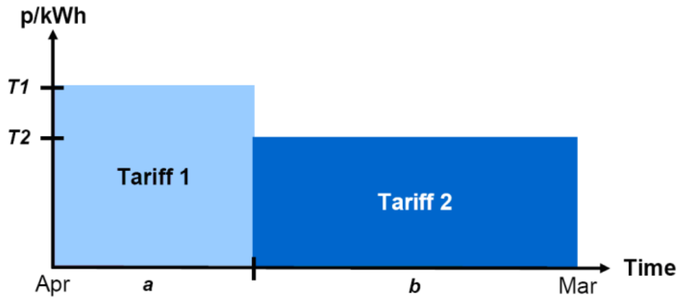
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

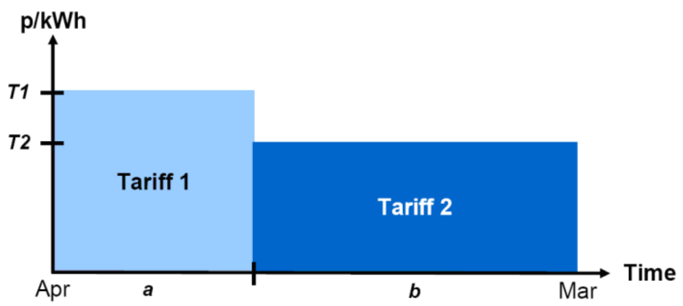
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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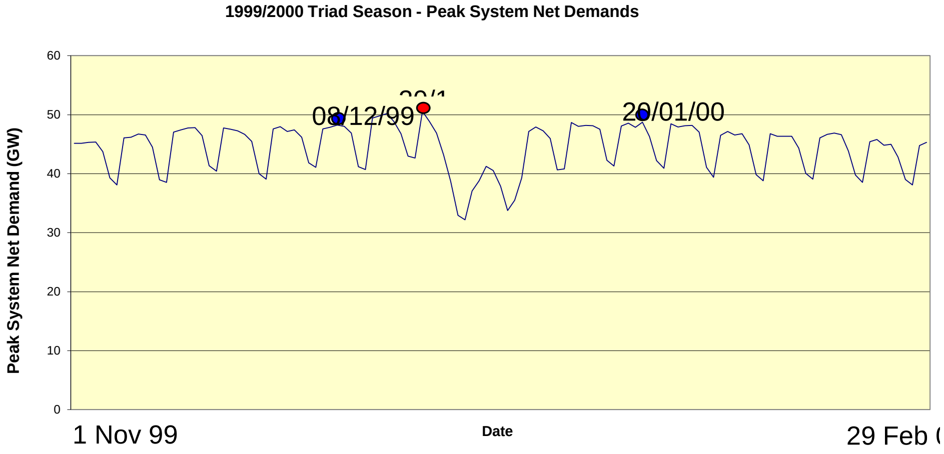


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:



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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17,000,000\text{kWh} - 18,000,000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1,000,000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16,700,000\text{kWh} – 17,000,000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

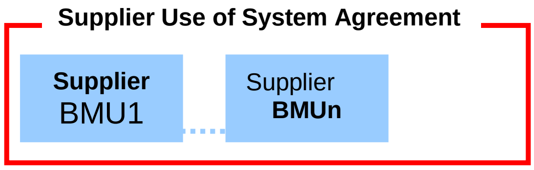
**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

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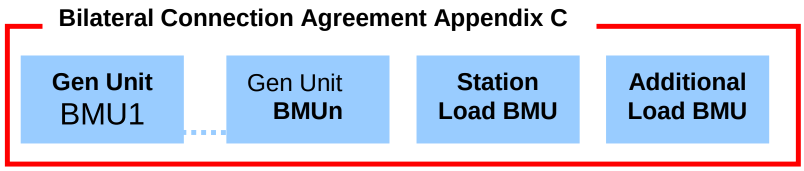
**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.18.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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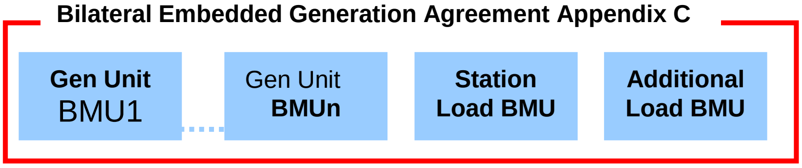
| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
|   | |
| Demand Charges | Generation Charges |
| See **14.17.14, 14.17.15 and 14.17.18**. | See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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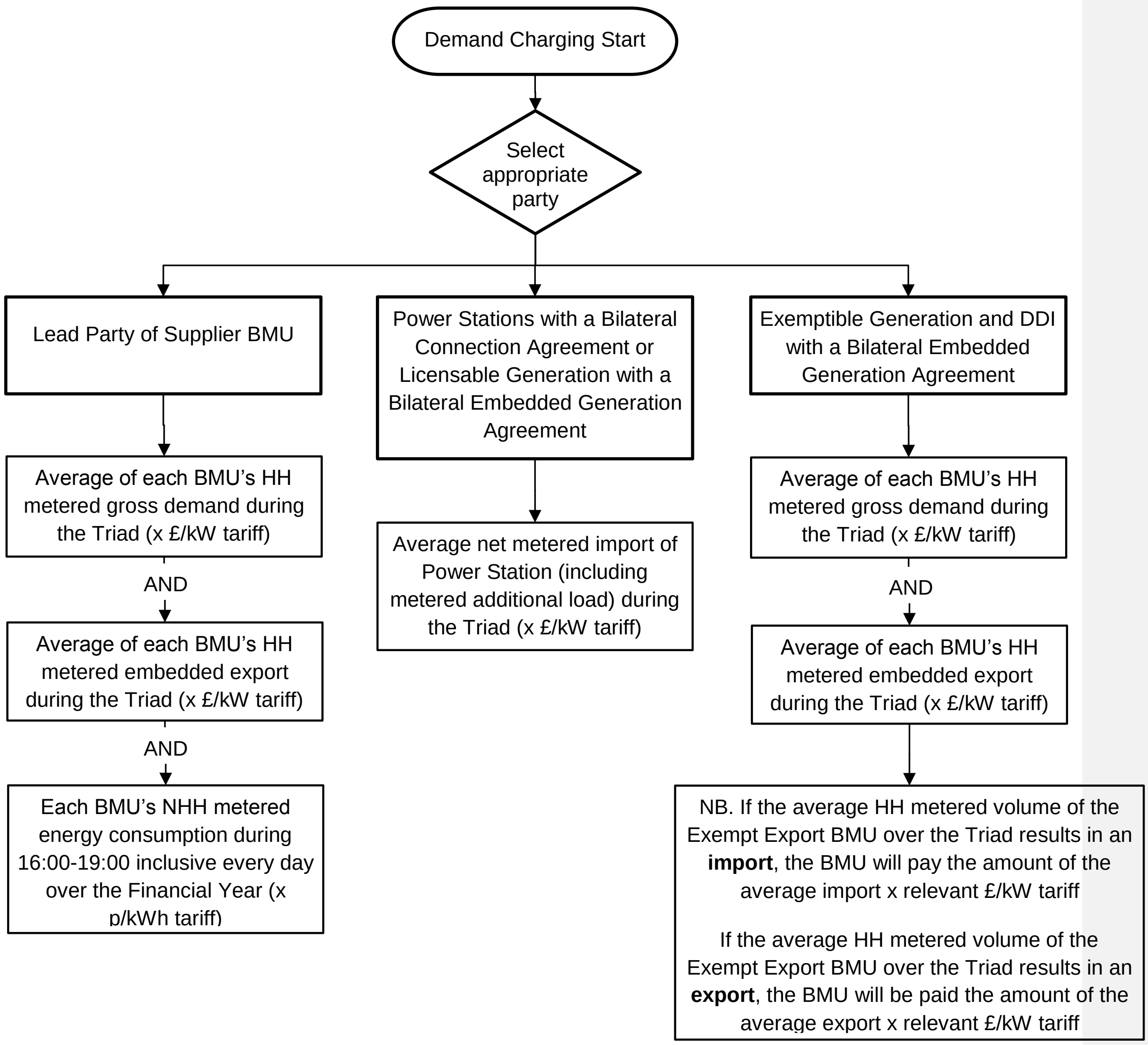
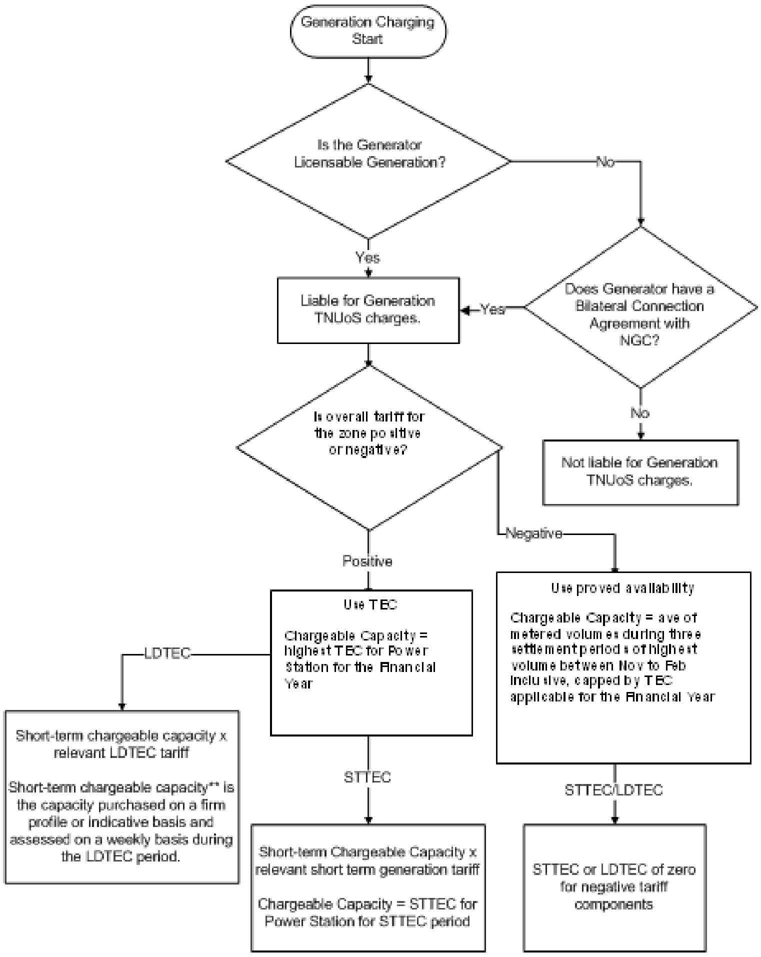



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

## Generation Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

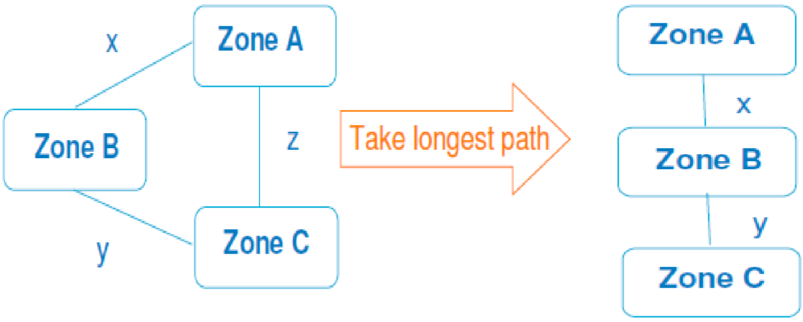
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

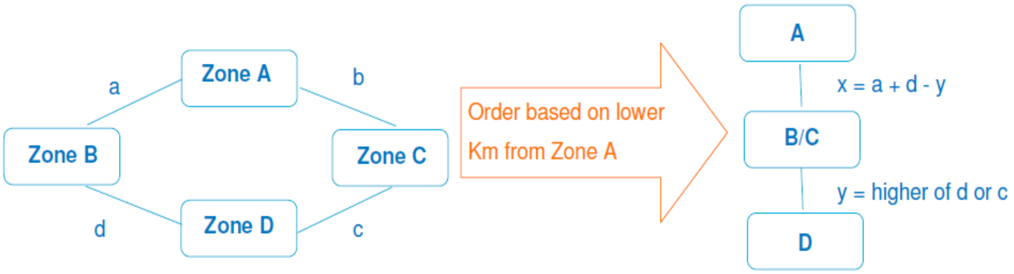
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

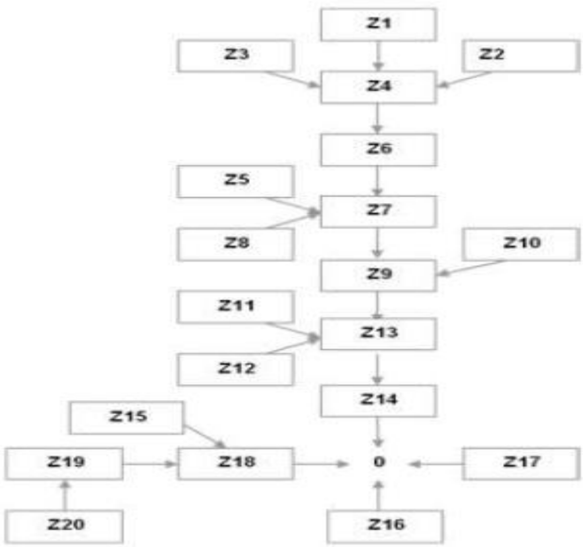
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| **400kV OHL expansion constant calculation** | **Ave £/MWkm** |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A – ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

| | | |
|---|---|---|
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff for the demand zone; |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff for the demand zone, and |
| EX | = | $ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$ |

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

Deleted: 113

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

Deleted: 114

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS} \times G_{Gi} \times ALF\right) = ITRR_{G\,YRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

Deleted: 115

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}\left(EET_{Di} \times EEV_{Di}\right)$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff: **Deleted:** 116

$$\sum_{k} \frac{NLMkm_{Gj}^{\;L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors: **Deleted:** 117

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are: **Deleted:** 118

| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period. **Deleted:** 119

14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components: **Deleted:** 120

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

$ELT_{Gi}$ = Effective Local Tariff (£/kW)

$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

$ELT_{Gi}$ = $LT_{Gi}$

Where

$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for

FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_G = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_j$$

Where

$LCRR_G$ = Local Charge Revenue Recovery

$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the

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relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

### Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$



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$$RT_D = \frac{(p \times TRR) - I}{}$$

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14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit

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amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

## Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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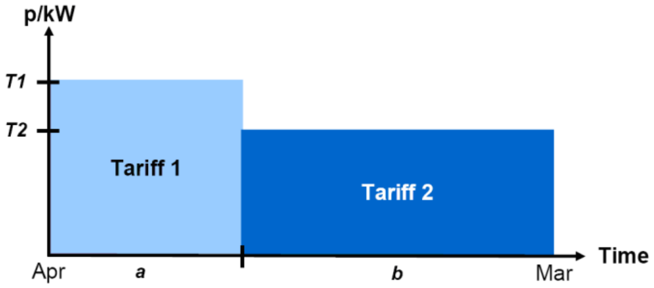
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

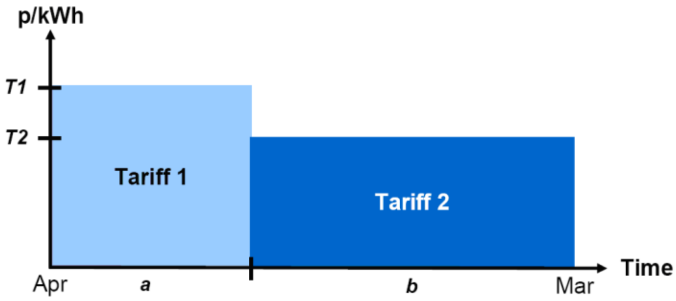
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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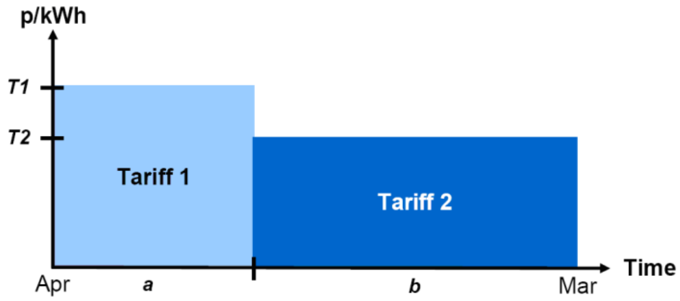
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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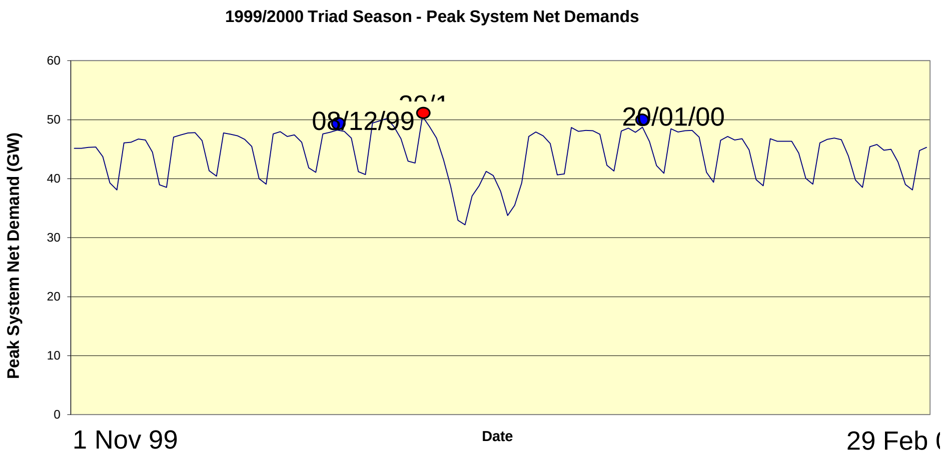


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

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- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

## Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

$= (9{,}000kW - 7{,}200kW) \times$ £10.00/kW

$= 1{,}800kW \times$ £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

## Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

$= (-500kW - -600kW) \times$ £5.00/kW

$= 100kW \times$ £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

## Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh - 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** | **Station Load BMU** | **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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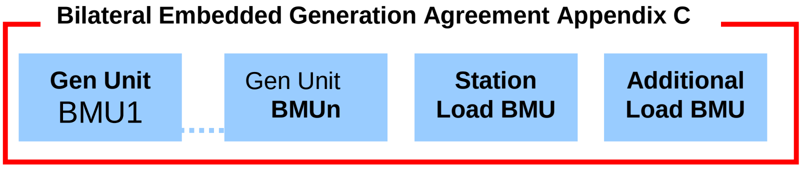
| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
|  | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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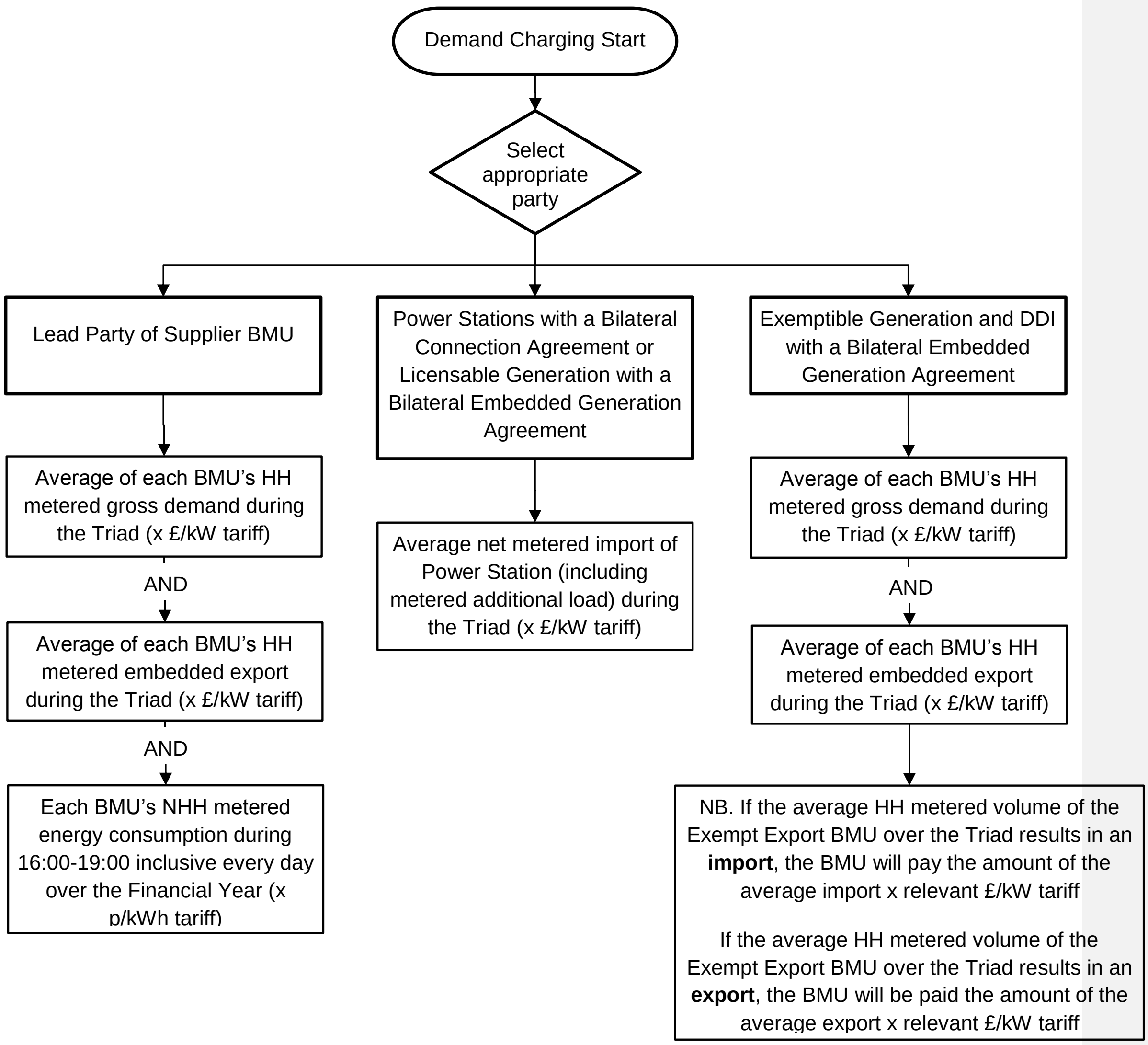
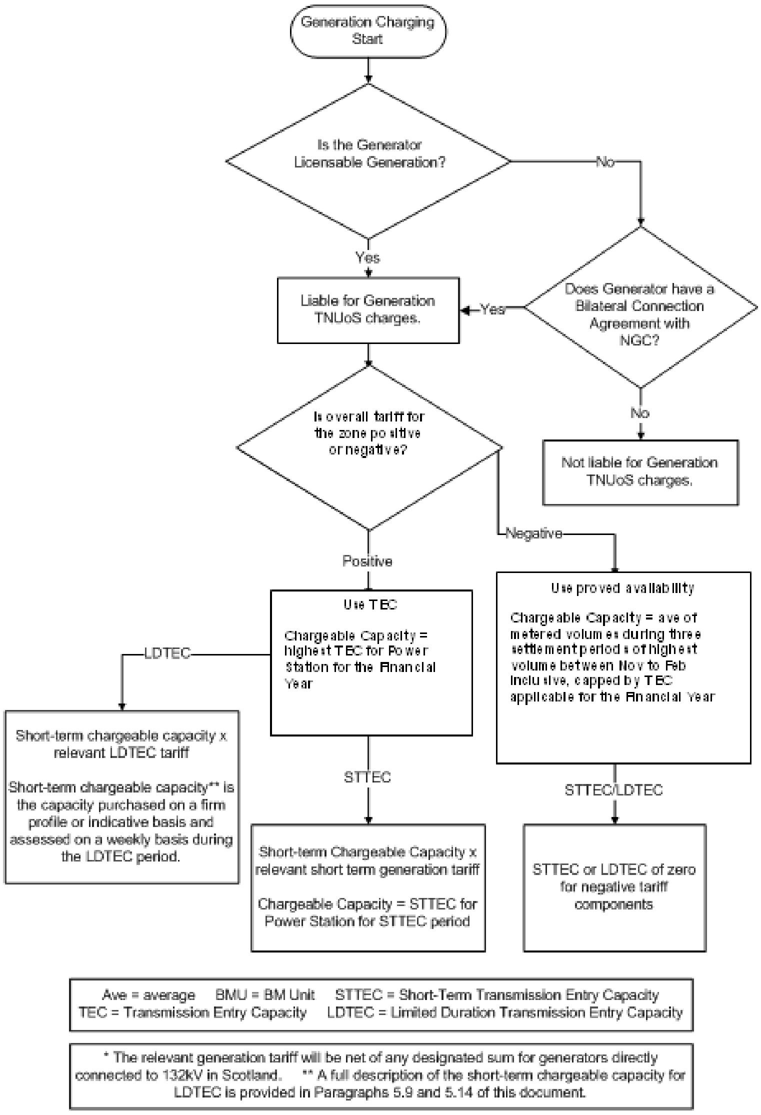



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

Deleted: h

where:

T = 10,000 kW (period November 2003 to February 2004)

Deleted: h

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

Deleted: h

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

Deleted: h

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

# CMP264 WACM7

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

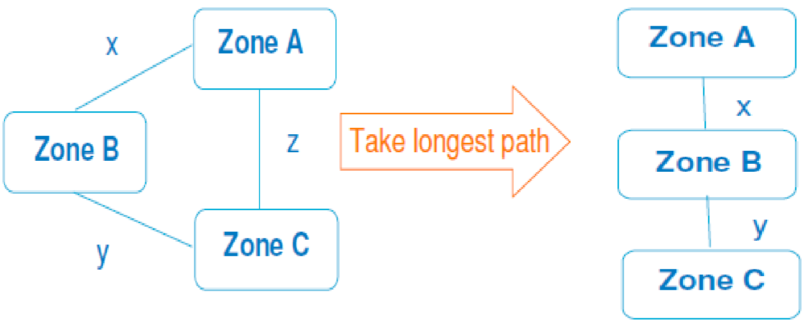
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

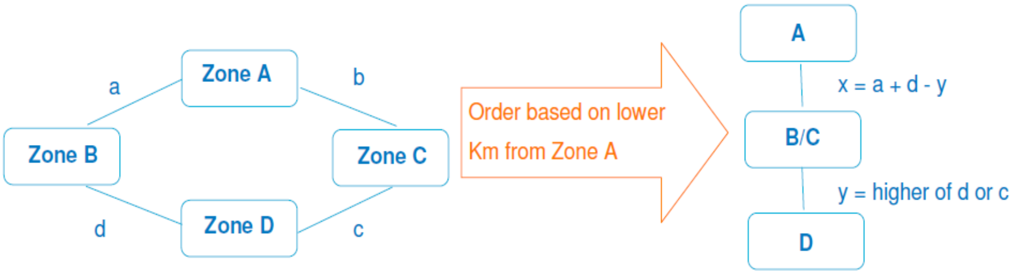
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

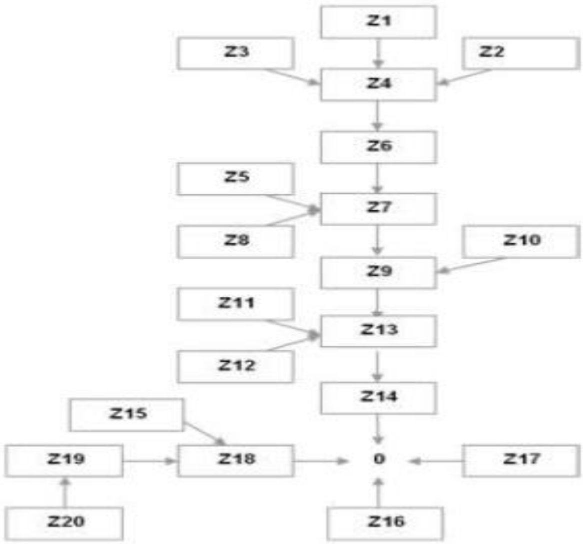
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

## Offshore Interlinks

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year “t” the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))) + ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$$

Second charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))) + ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$= ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$$

Where
XP = Value of demand residual in charging year prior to implementation

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiPS} \times D_{Di}) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period. **Deleted:** 119

14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components: **Deleted:** 120

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs: **Deleted:** 121
$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability. **Deleted:** 122

$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by: **Deleted:** 123

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components. **Deleted:** 124

14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under |

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

### Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

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Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag

- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

FT = Final annual TNUoS Tariff expressed in £/kW

Gi = Generation zone

STTEC Period = A period applied for in days as defined in the CUSC

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left( \frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12} \right)$$

Deleted: $Annual\ Liability_{D}$

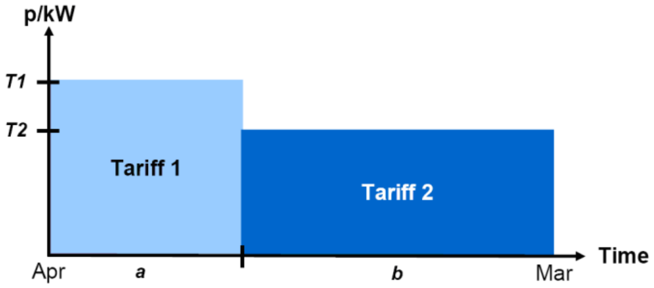
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

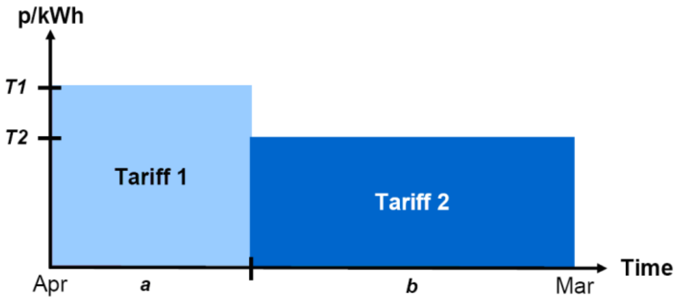
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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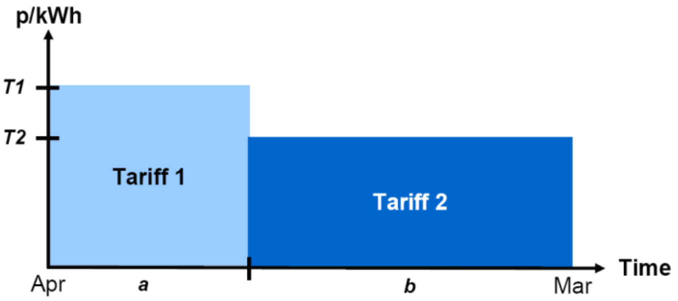
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.
- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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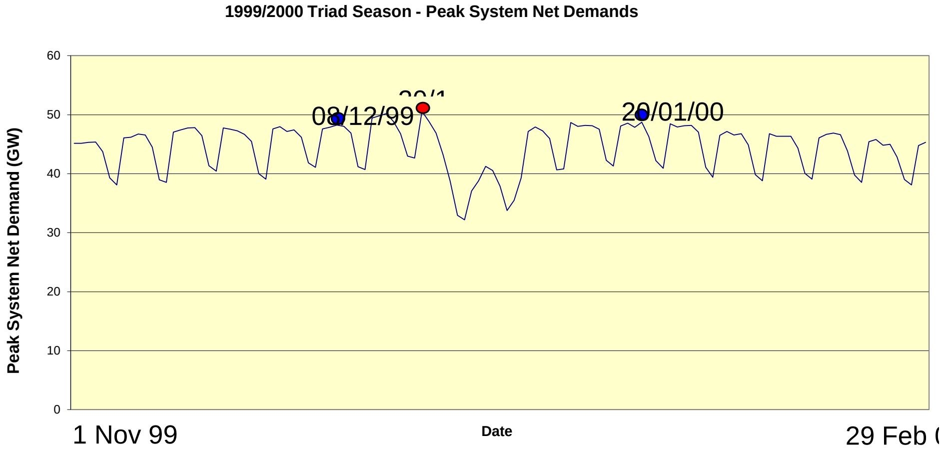


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company. **Deleted:** 18

## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation. **Deleted:** 19

### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges. **Deleted:** 20

### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad. **Deleted:** 1

14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months **Deleted:** 22

concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/



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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Deleted: Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| SUPPLIER | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| POWER STATION WITH A BILATERAL CONNECTION AGREEMENT | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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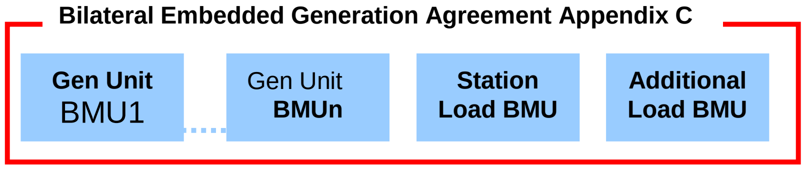
| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
|   | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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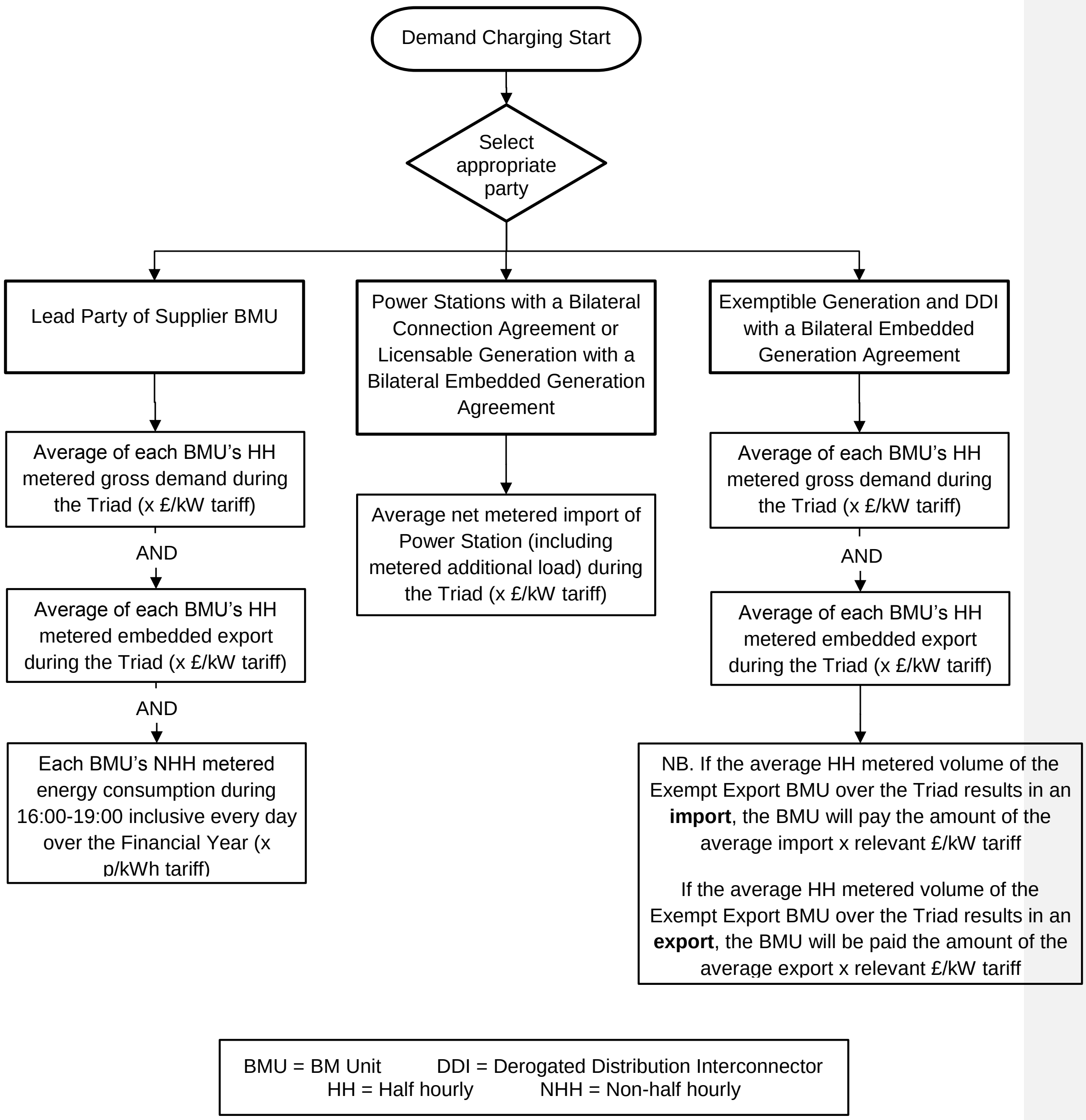
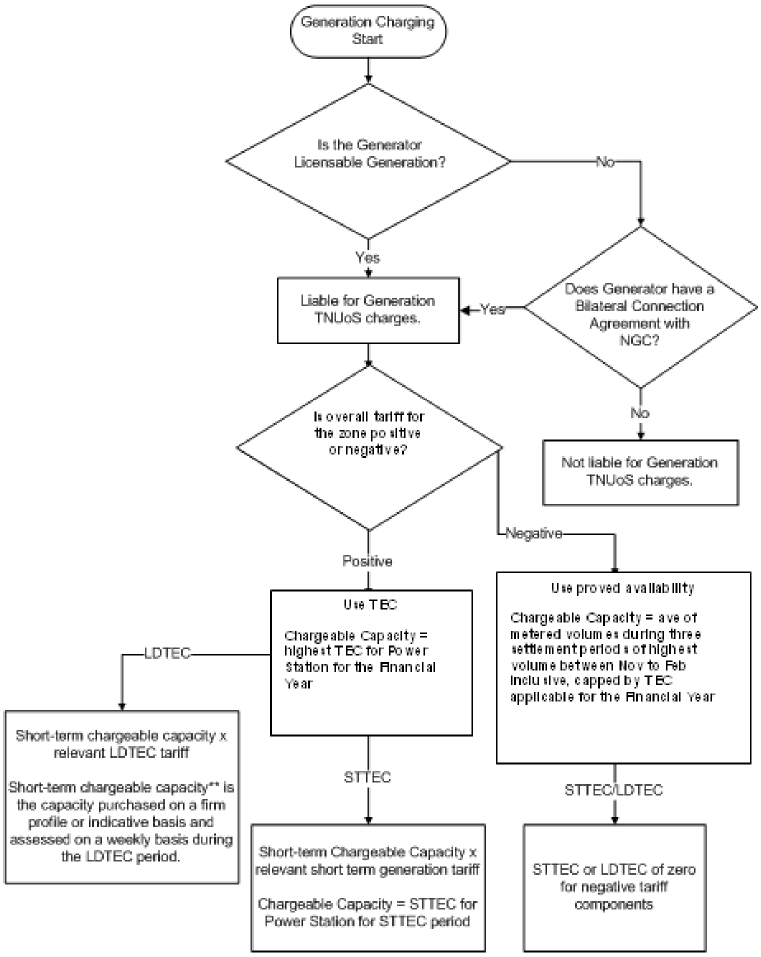


## Generation Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)



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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| **Generation Plant Type** | **Peak Security Background** | **Year Round Background** |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| Ref | Description of works | Adjustments |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

### Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_{b} - ZIkm_{a}$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

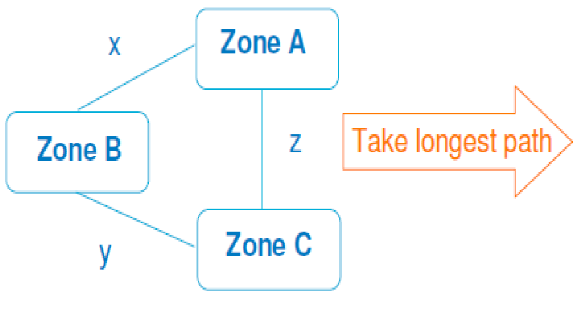
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

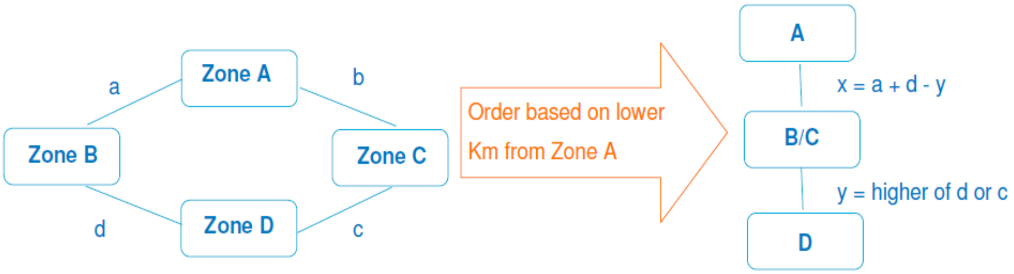
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

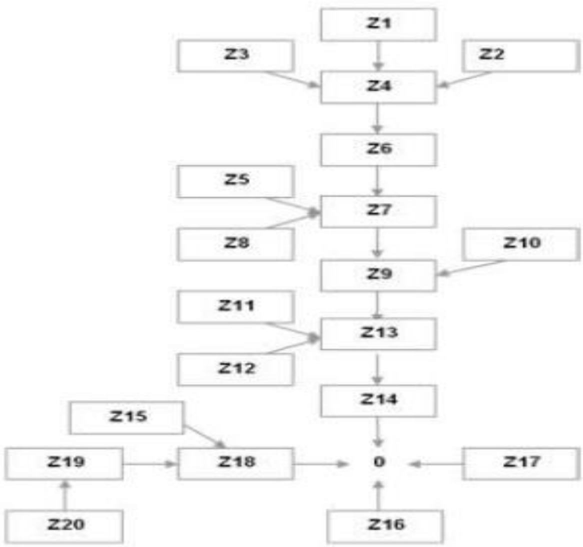
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = £32.30 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

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14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

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14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE}=\sum_{Di=1}^{14}\left(EET_{Di}\times EEV_{Di}\right)$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

### Deriving the Final Local Tariff (£/kW)

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

$$\sum_{k} \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_{k}$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

### Onshore Local Substation Tariff

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of

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time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

### Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

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$$RT_D = \frac{(p \times TRR) - I}{}$$

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For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$ and $$FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum,

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determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} *100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff} \quad (\text{£/kW/period})$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

### Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

### Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

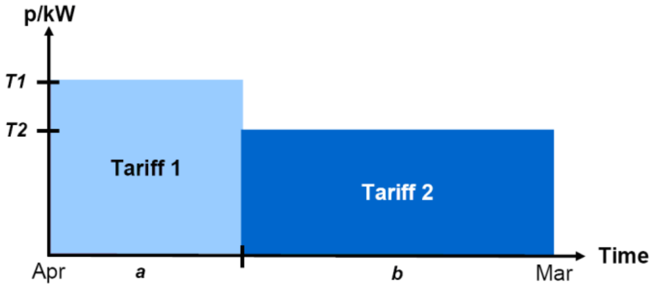
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

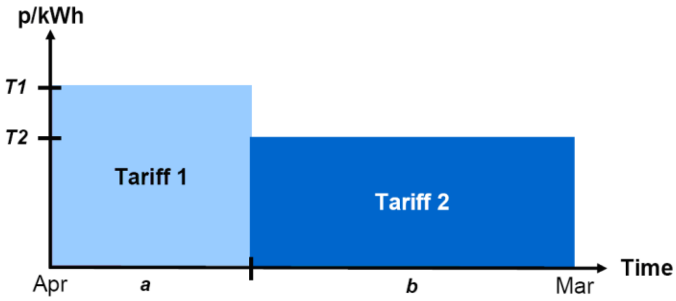
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Annual Liability $_D$

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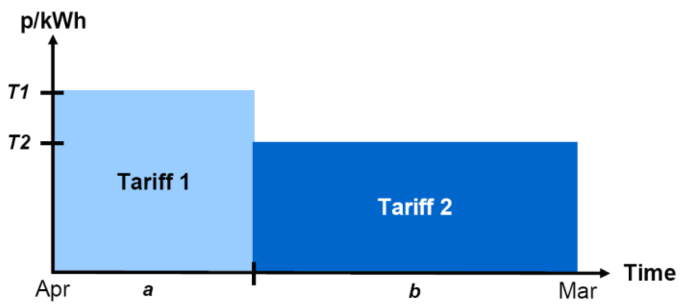
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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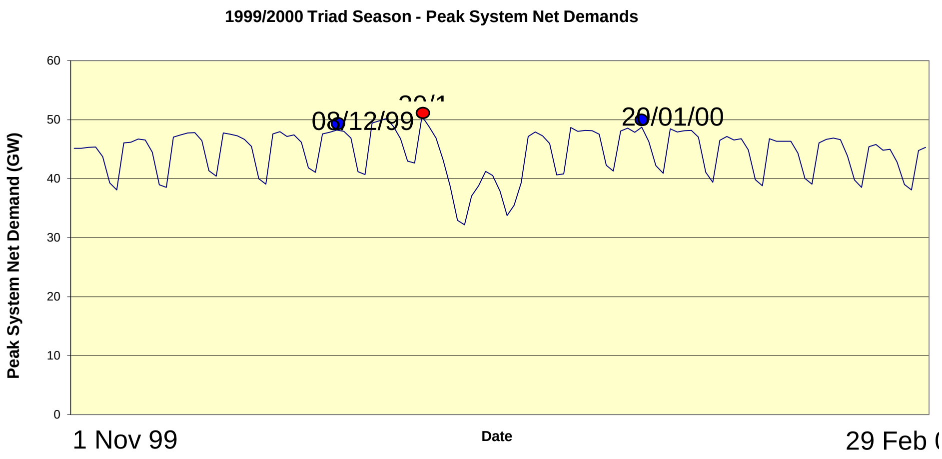


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:
- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A – HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><th colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</th></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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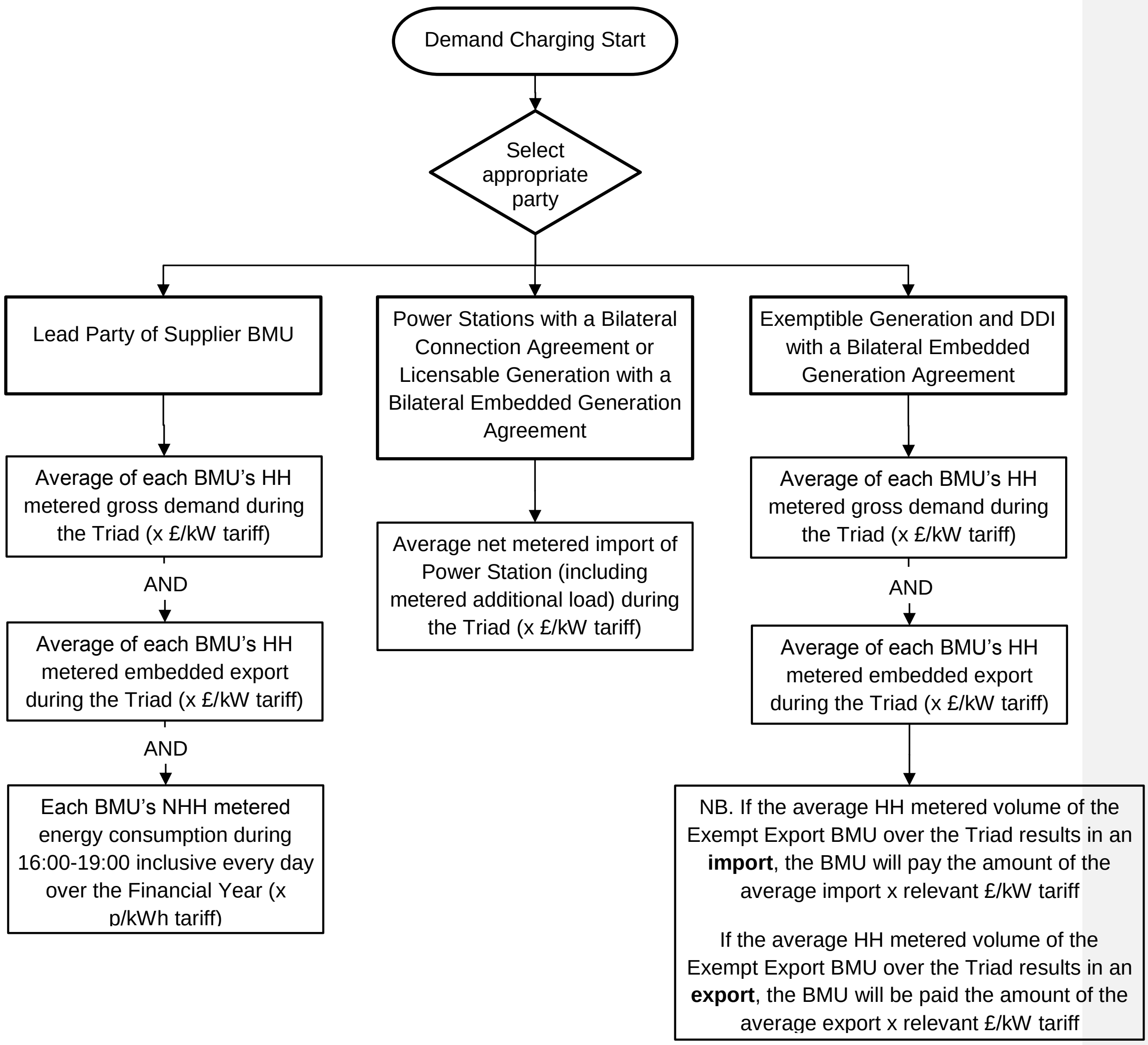
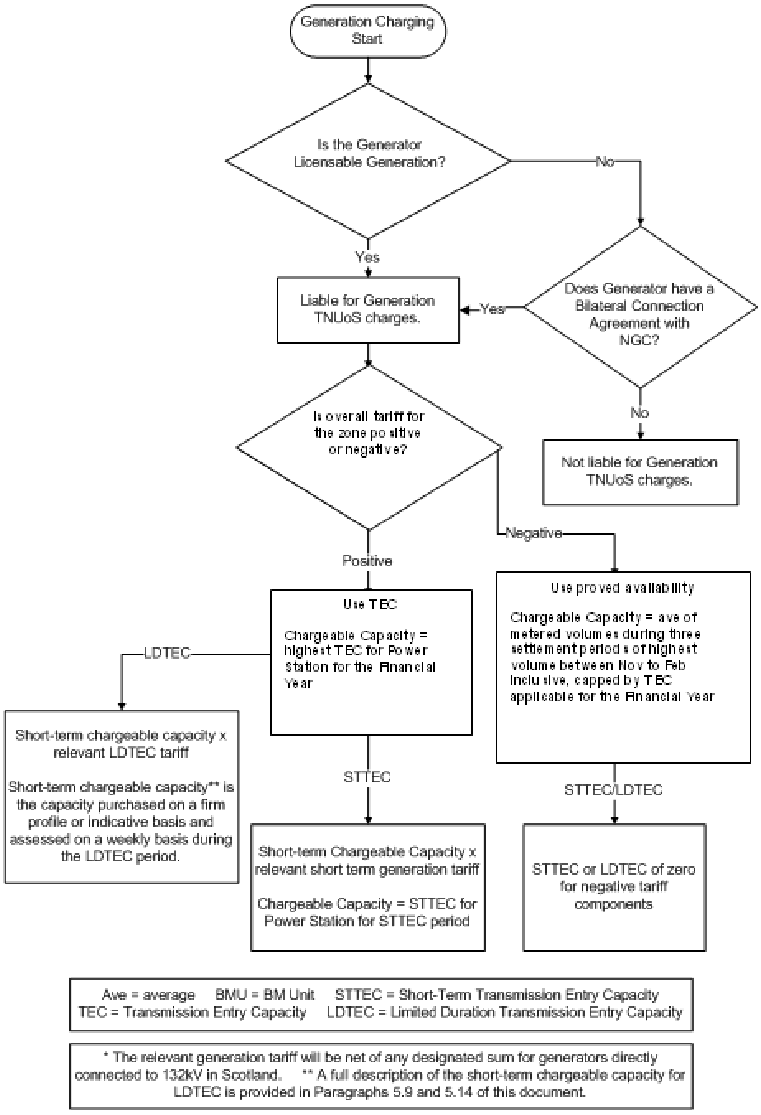



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Liable for Generation TNUoS charges.
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

# CMP264 WACM9

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| Ref | Description of works | Adjustments |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

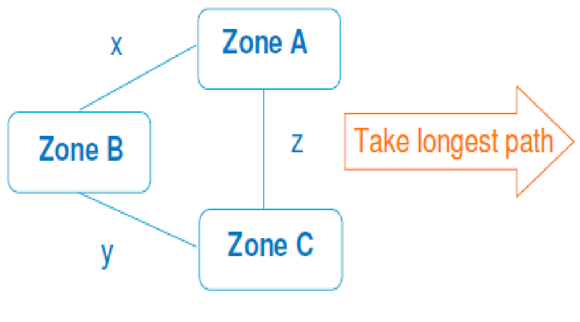
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

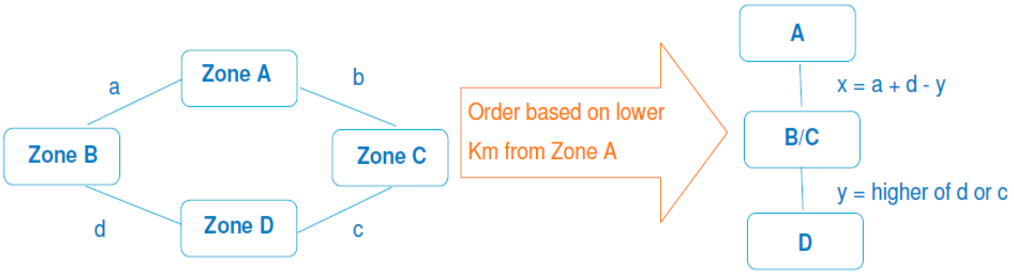
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

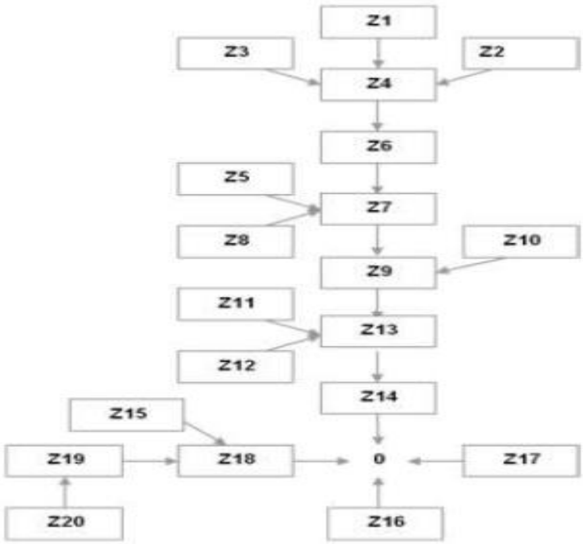
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

## Offshore Interlinks

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$\underline{LocalSF_{initial}}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = For the first charging year following implementation, £34.11 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.
In every subsequent charging year, AGIC + (£18.50 in April 2019 prices; indexed each year by the RPI formula set out in 14.3.6).

Where
AGIC= The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where
$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type

Deleted: 113

n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS} \times G_{Gi} \times ALF\right) = ITRR_{G\,YRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

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$$ITRR_{EE} = \sum_{Di=1}^{14} (EET_{Di} \times EEV_{Di})$$

Where

| | | |
|---|---|---|
| | $ITTR_{EE}$ | = Initial Revenue impact for Embedded Exports |
| | $EEV_{Di}$ (MW) | = Forecast Embedded Export metered volume at Triad |

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

PVC$_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

SG$_{t-1}$ = The proportion of the under/over recovery included within R$_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

ET$_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW (ET$_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances ITT$_{GiPS}$, ITT$_{GiYRNS}$ and ITT$_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $$RFT_{Di} = 0$$

For *i*=z+1 to 14: $$RFT_{Di} = FT_{Di} + NRRT_D$$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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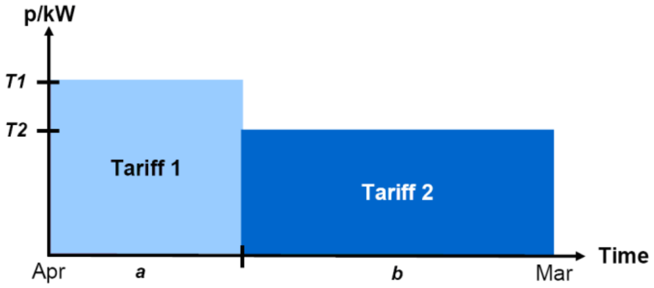
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

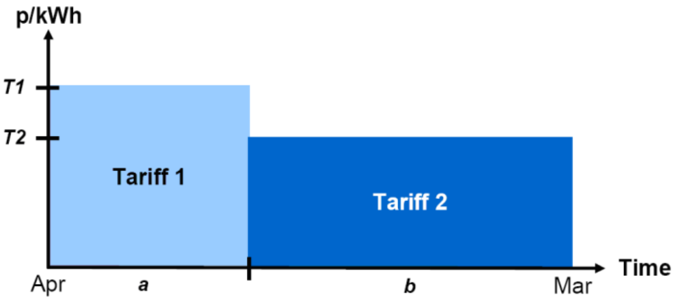
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

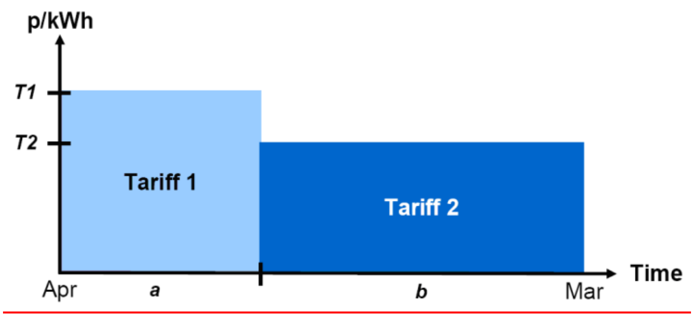
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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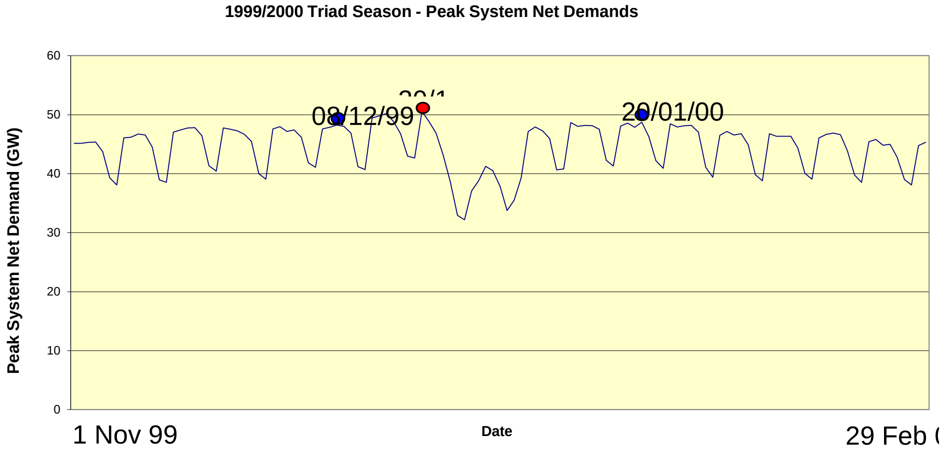


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:



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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or



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b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge $= \frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

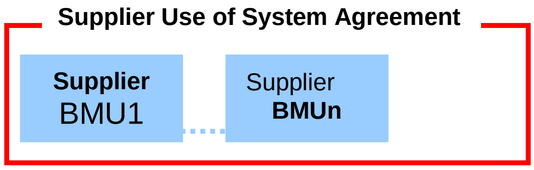
**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

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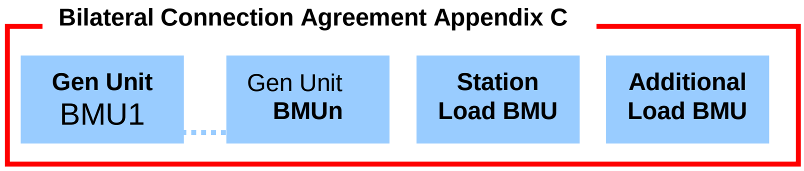
**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.18.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 ... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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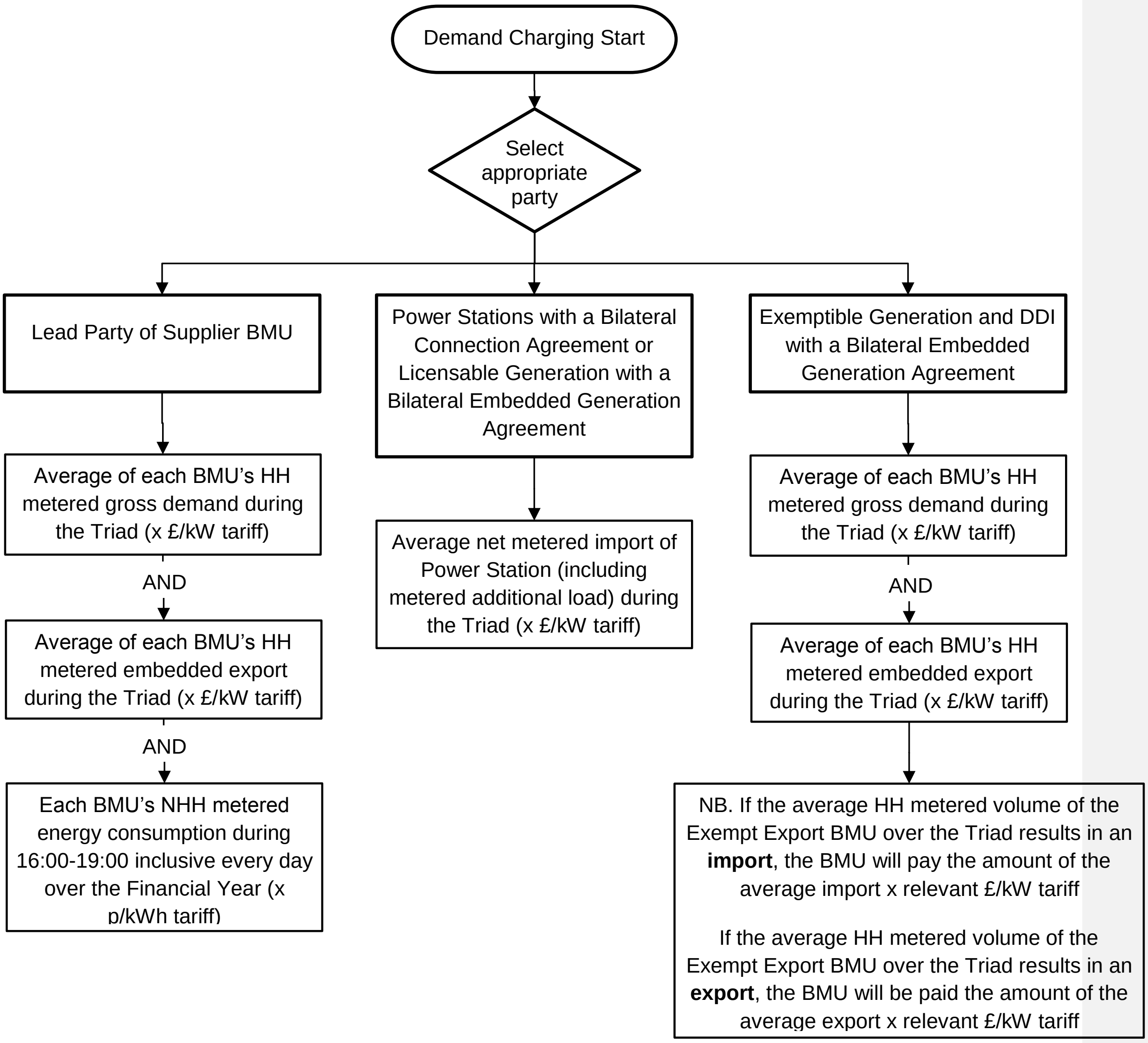
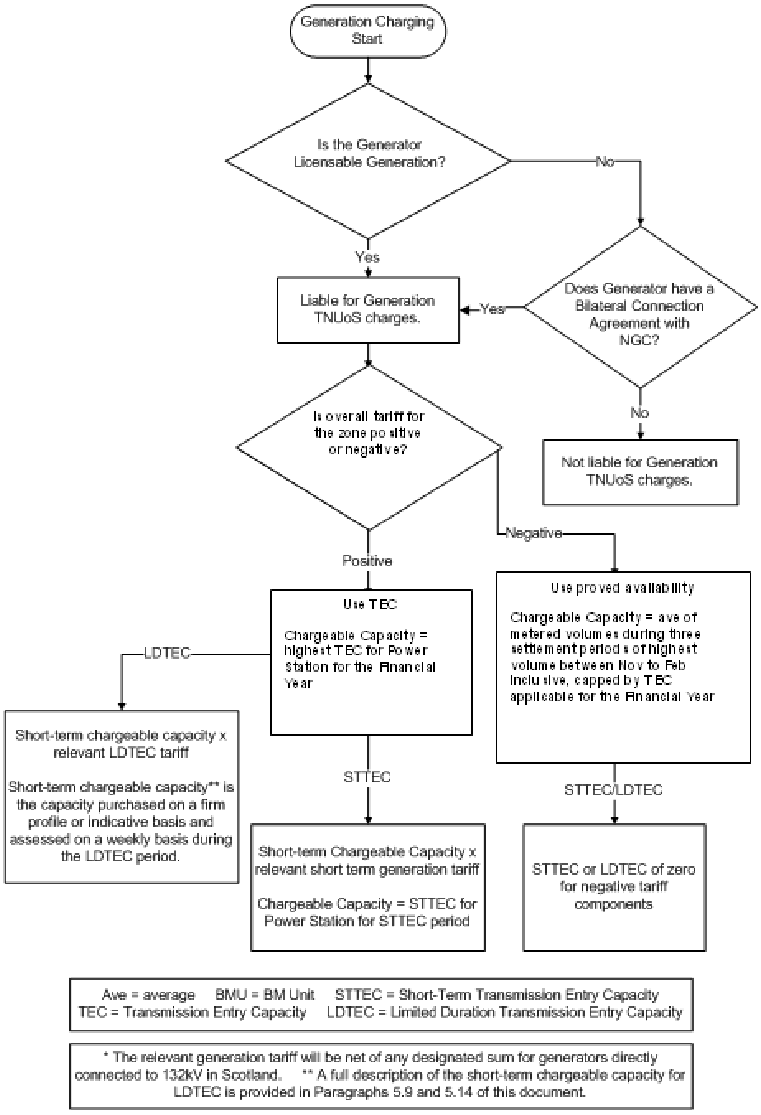



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

### Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

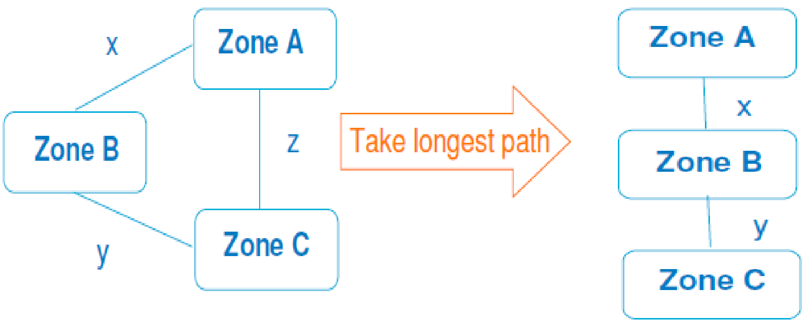
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

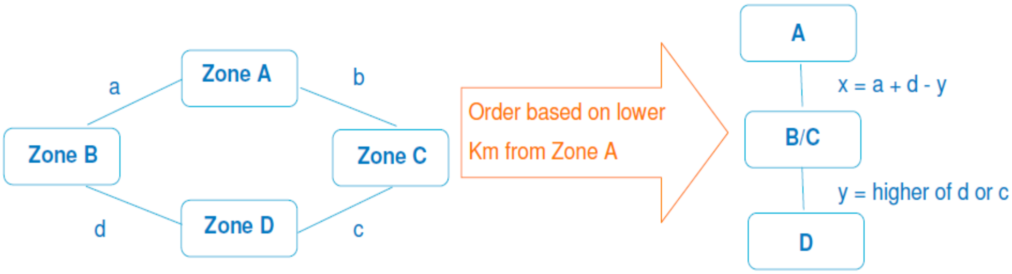
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

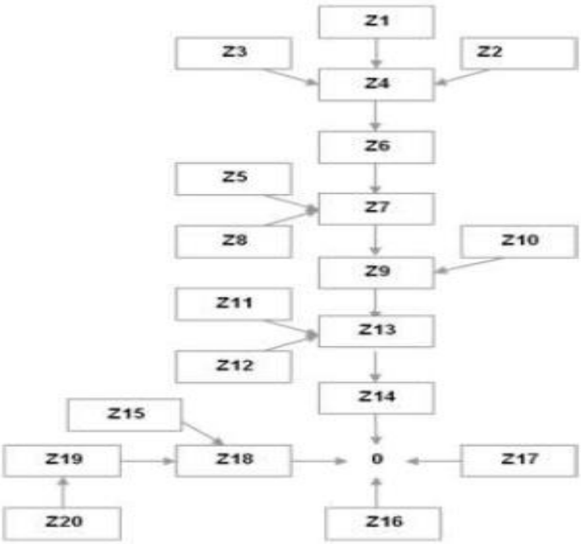
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and

ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:

$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:

$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:

$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$

and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = £45.33 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

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14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:
$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

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14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

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14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

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**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of

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time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

Deleted: ¶ $RT_D = \frac{(p \times TRR) - I}{}$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum,

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determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

**Deleted:** $Annual\ Liability_{D}$

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

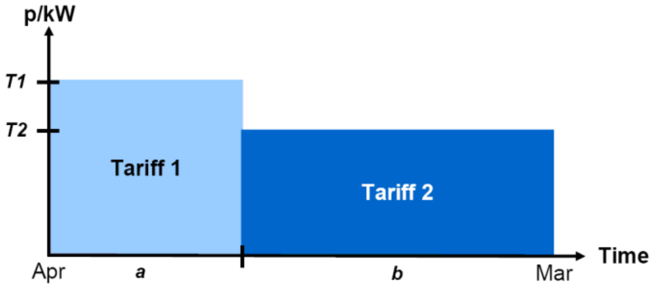
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ \ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ \ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

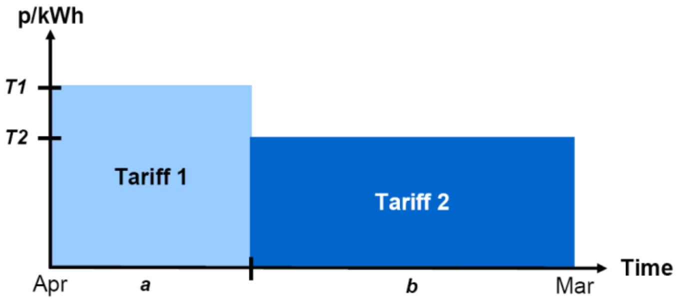
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

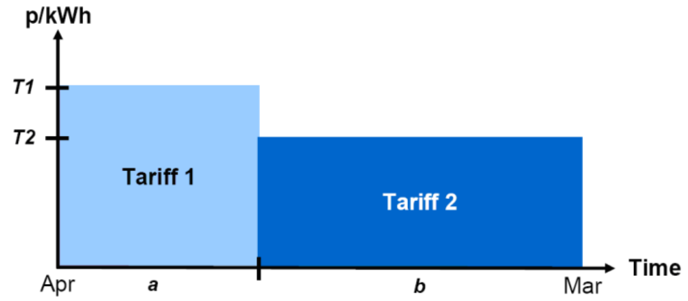
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**



Annual Liability
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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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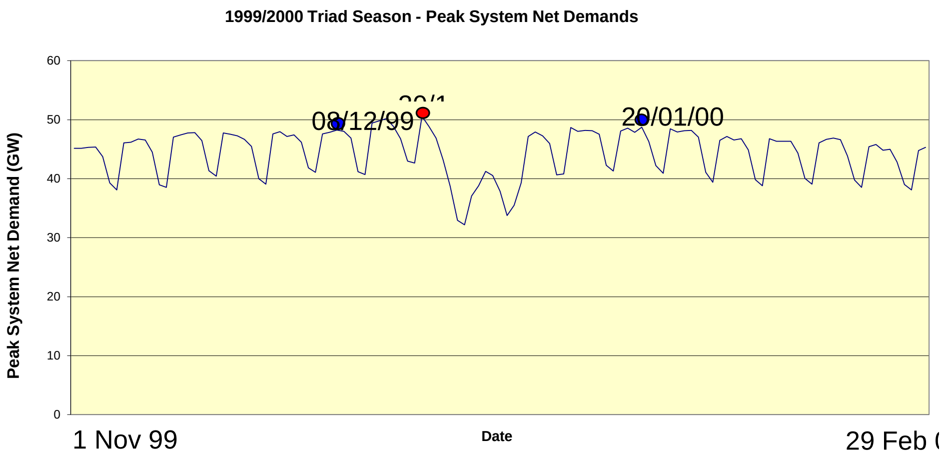


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:



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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

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b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \underline{\mathbf{£3.45/kW}}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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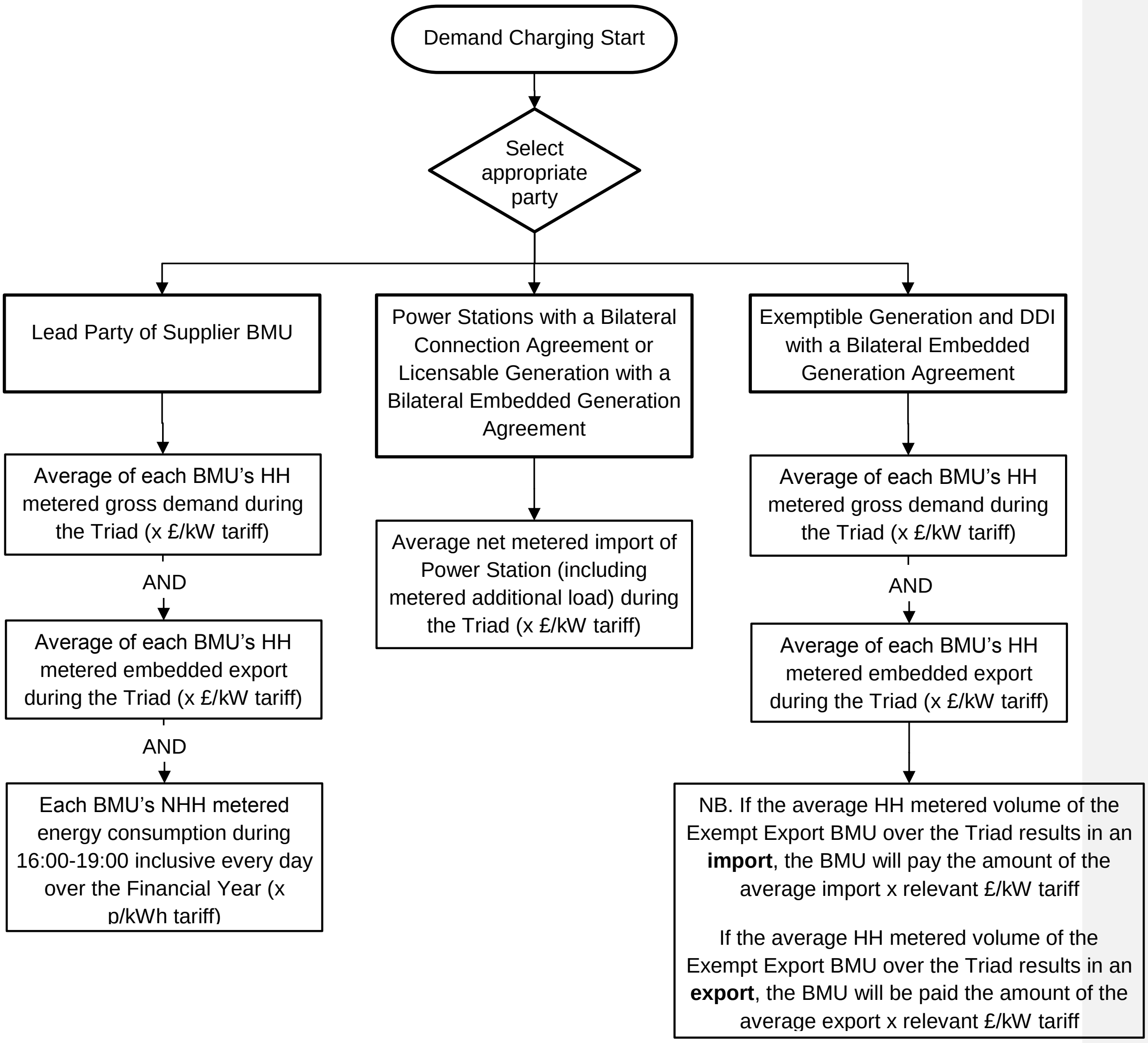
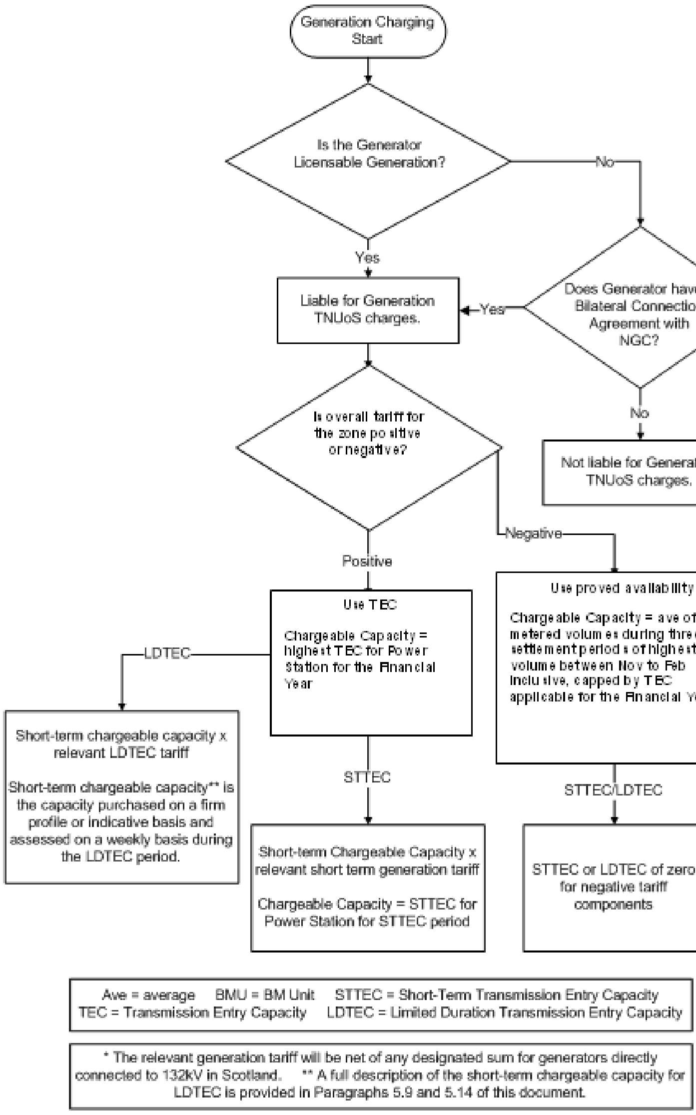



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| Ref | Description of works | Adjustments |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

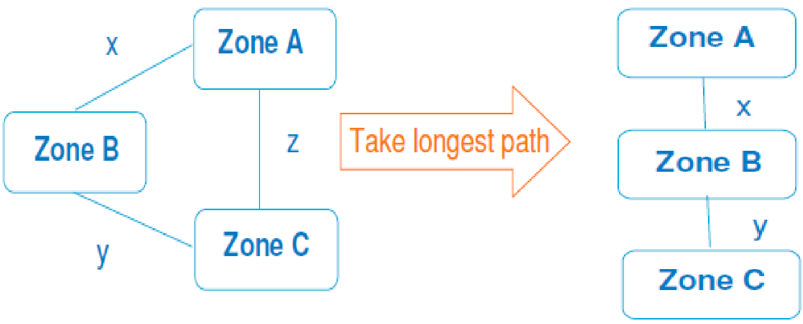
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

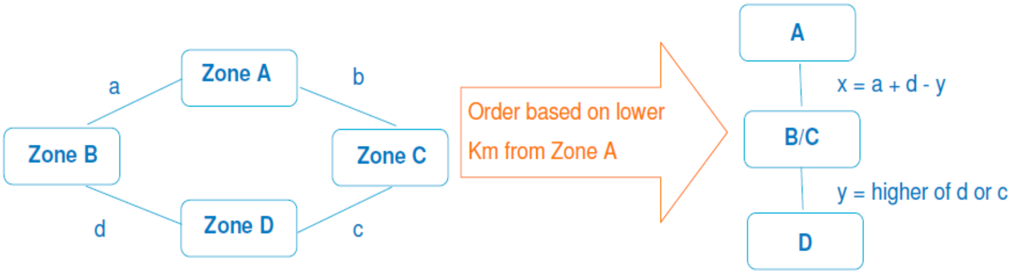
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

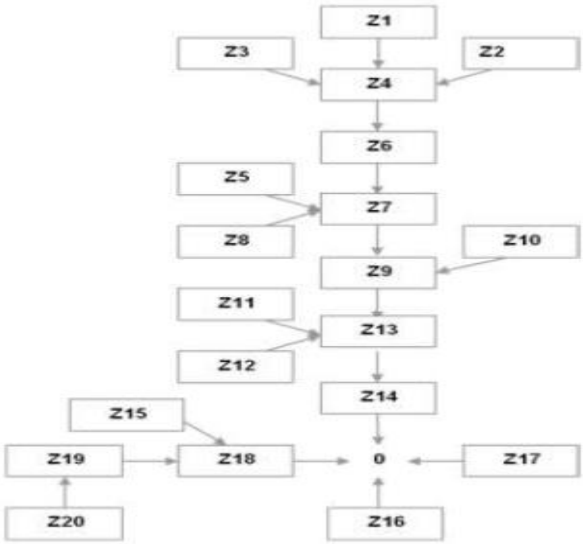
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| **400kV OHL expansion constant calculation** | **Ave £/MWkm** |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX =

$$AEX11 = \frac{(p \times TRR) - OC - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14}(D_{Di} + EEV_{Di})}$$

Where
AGX11= Residual Tariff for embedded Affected Embedded Exports
P = Proportion of revenue to be recovered from demand
OC = Offshore Costs paid by demand
$ITRR_{DPS}$ = Peak Security Initial Transport Revenue Recovery for demand
$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for demand
$D_{Di}$ = Total forecast Metered Triad Gross Demand for each demand zone $EEV_{Di}$
= Forecast Embedded Export metered volume at Triad (MW)

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS}\times D_{Di}\right)=ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE}=\sum_{Di=1}^{14}(EET_{Di}\times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ (MW) = Forecast Embedded Export metered volume at Triad

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

$ELT_{Gi}$ = Effective Local Tariff (£/kW)

$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$

Where

$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for

FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

$LCRR_G$ = Local Charge Revenue Recovery

$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under |

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag

- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff} \quad \text{(£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left( \frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12} \right)$$

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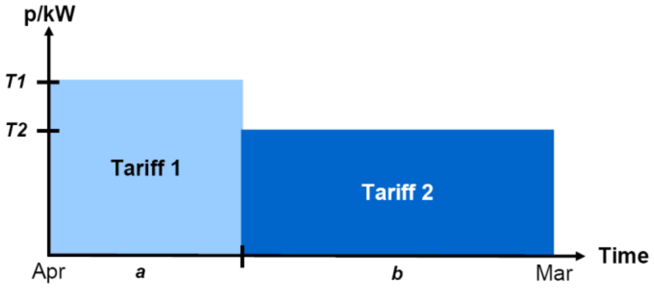
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

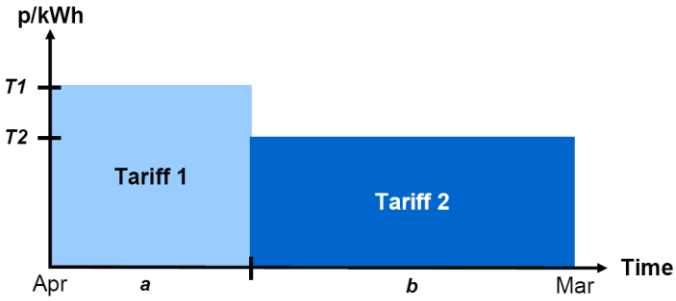
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

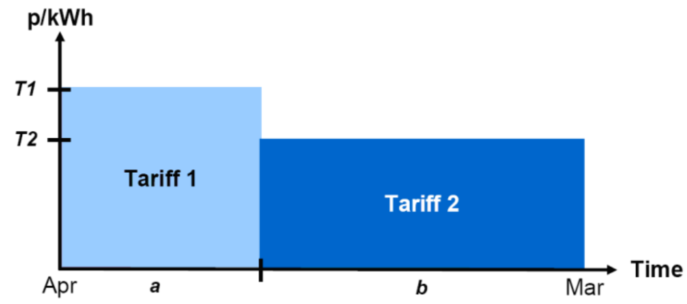
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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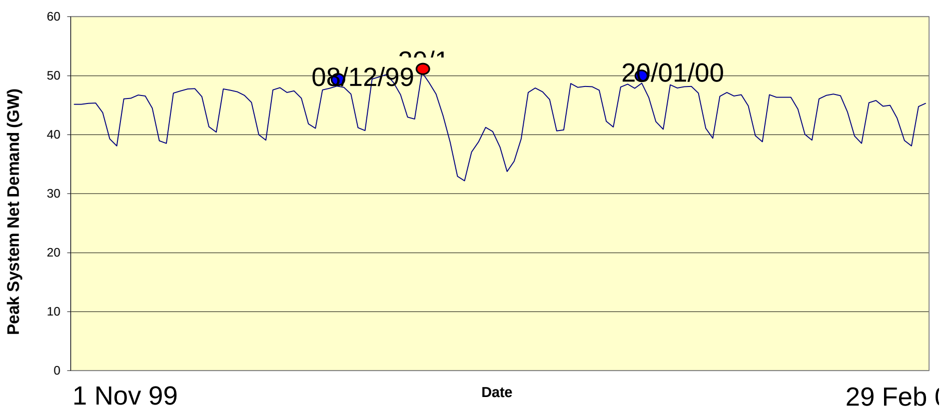
1999/2000 Triad Season - Peak System Net Demands




**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

## Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

## Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

## Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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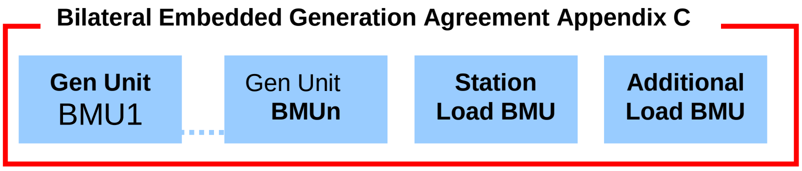
**PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT**




| Demand Charges | Generation Charges |
| --- | --- |
| See **14.17.14, 14.17.15 and 14.17.18.** | See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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# 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

## Demand Charges

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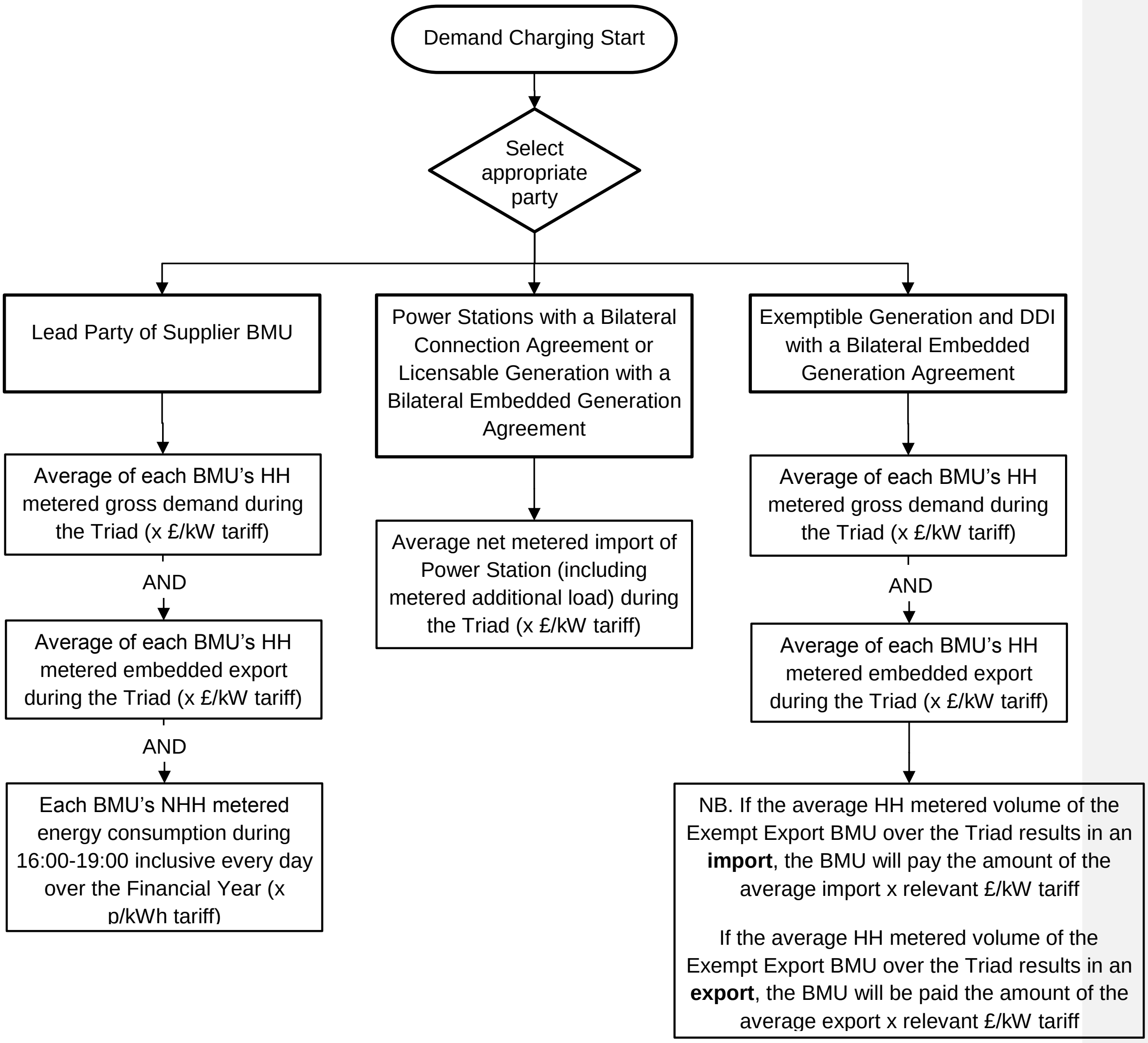
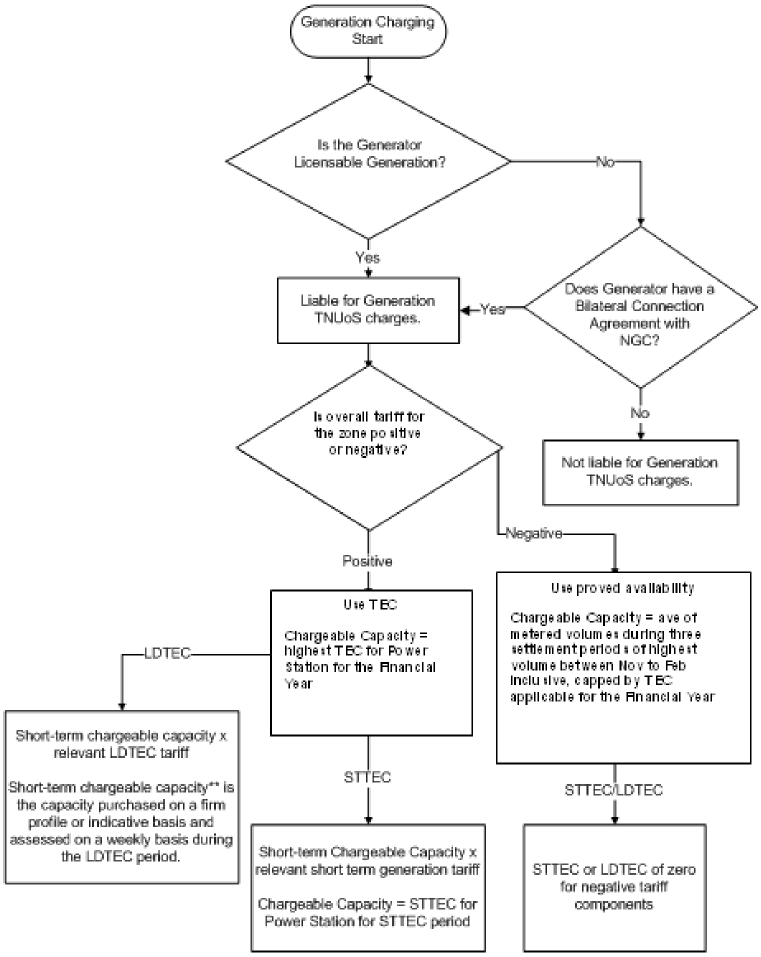



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Deleted: h

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| **Generation Plant Type** | **Peak Security Background** | **Year Round Background** |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

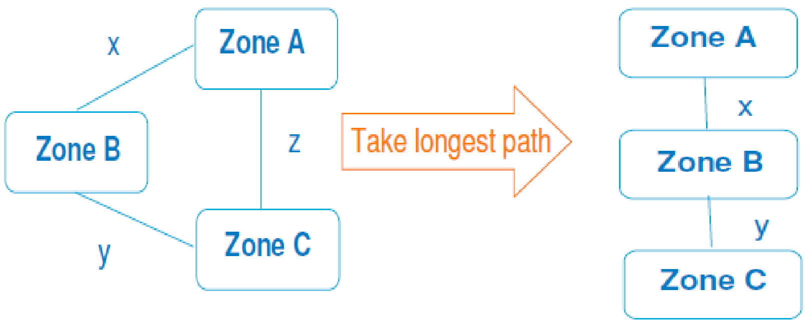
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

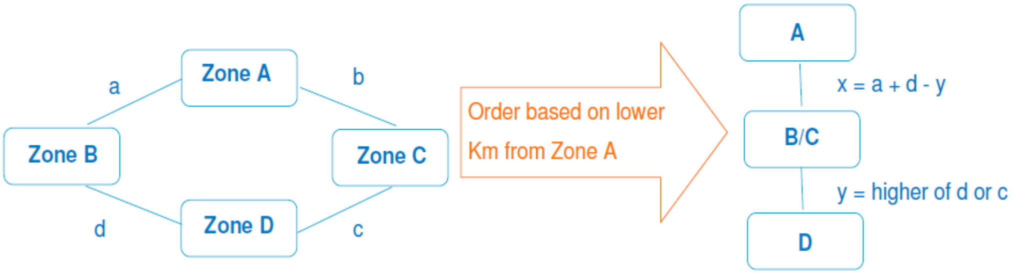
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

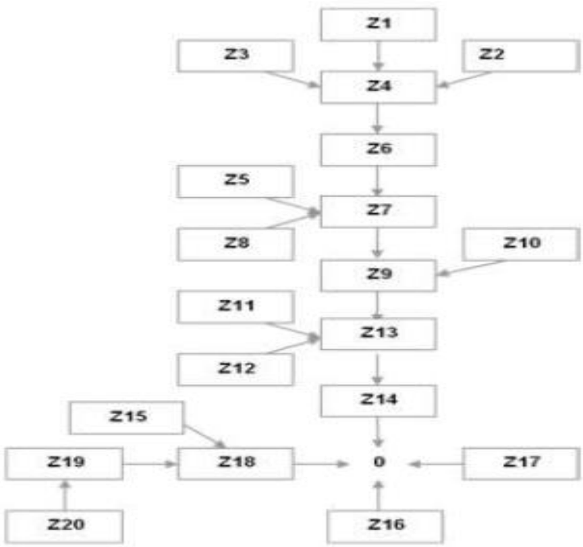
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner’s reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = $RT_G \times -1$

Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
    - In respect of a 'new build generating CMU'
    - Having more than one delivery year
    - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied

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by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}\left(EETA_{Di}\times EEVA_{Di}\right)$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| Substation Rating (b) | Connection Type (c) | Substation Voltage (a) | | |
|---|---|---|---|---|
| | | 132kV | 275kV | 400kV |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{G} = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_{j}$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

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$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

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14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

### Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

### Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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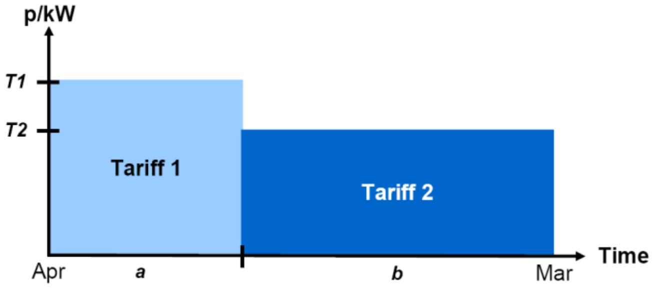
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

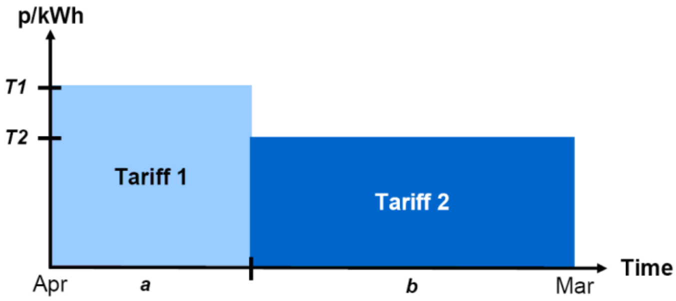
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

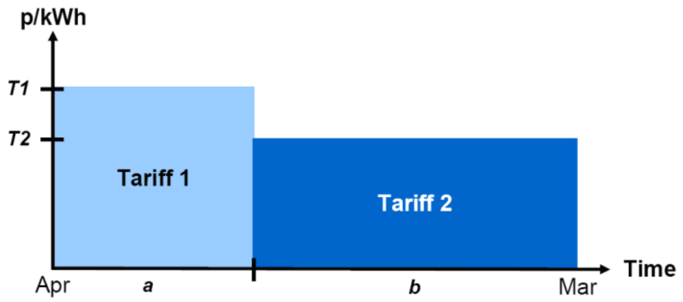
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**



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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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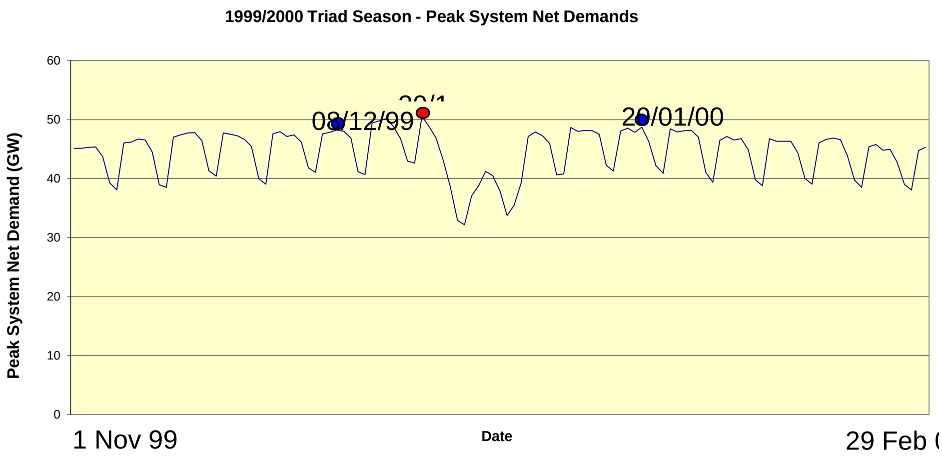


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

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14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:
- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User’s TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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£779m - £140m - -£10m = £12.98/kW
50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times £/kW$ Tariff

$= (9{,}000kW - 7{,}200kW) \times £10.00/kW$

$= 1{,}800kW \times £10.00/kW$

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times £/kW$ Tariff

$= (-500kW - -600kW) \times £5.00/kW$

$= 100kW \times £5.00/kW$

**= £500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} - 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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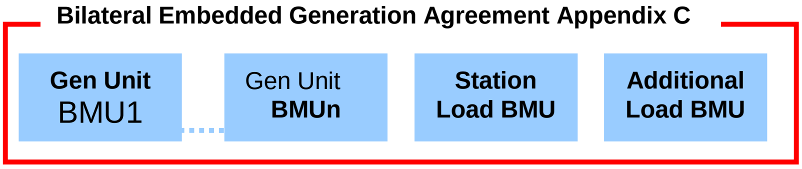
| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
|   | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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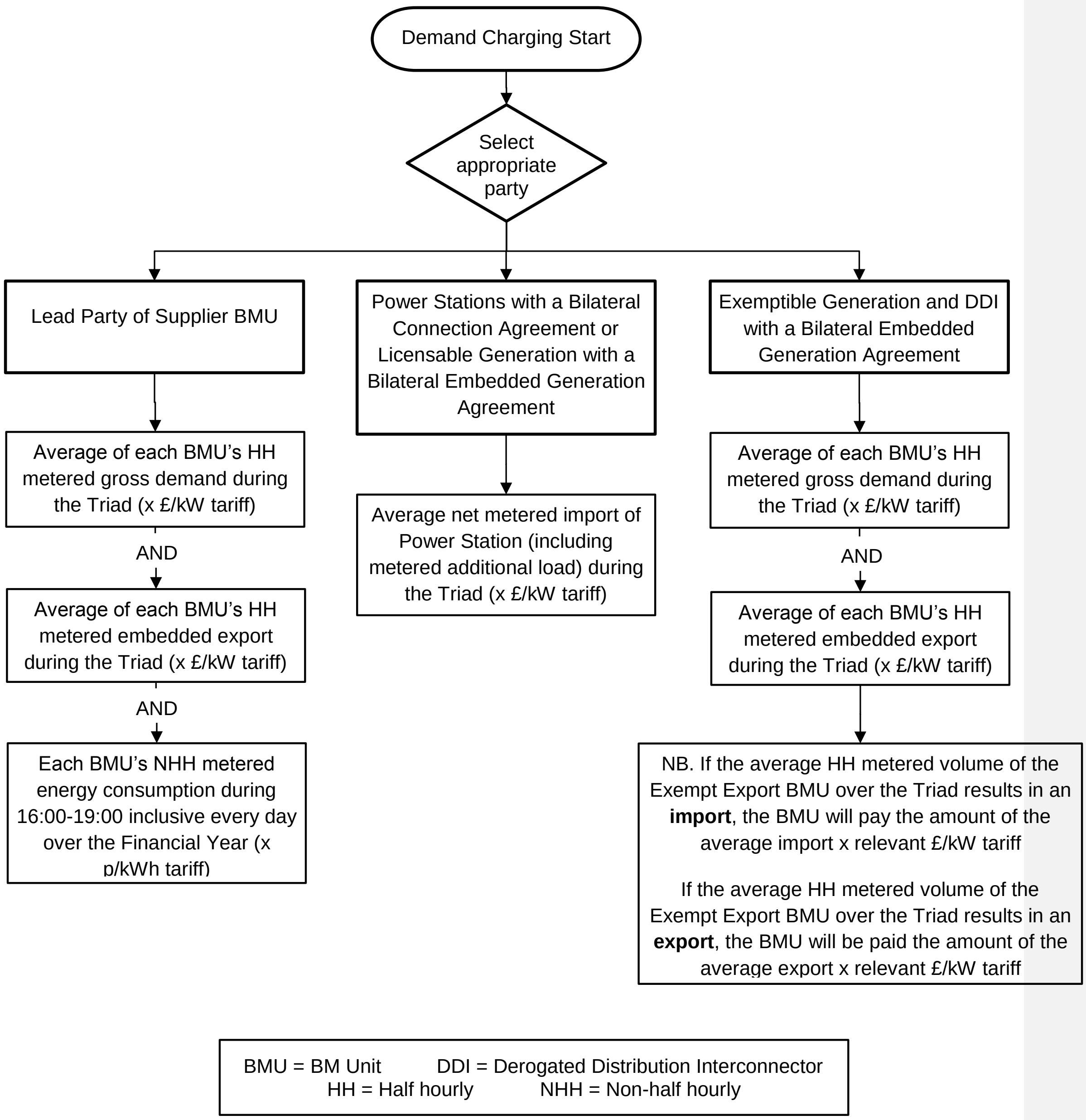
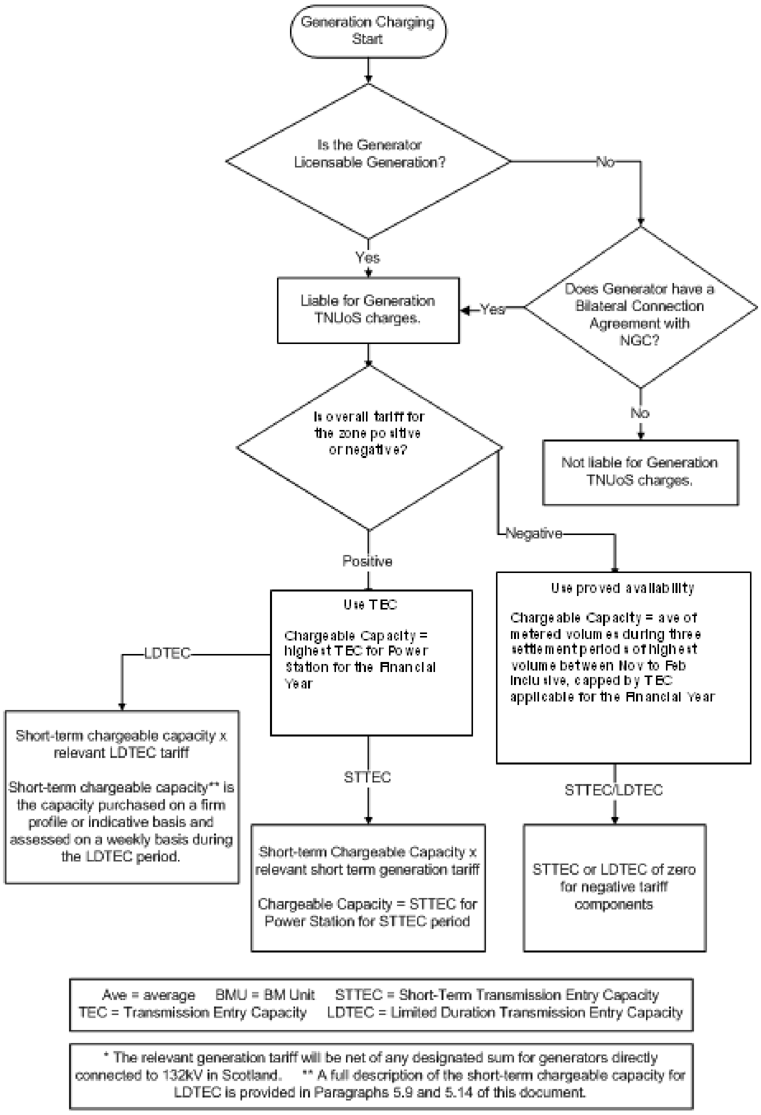


Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

$F = T$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

$F = T * D/P$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

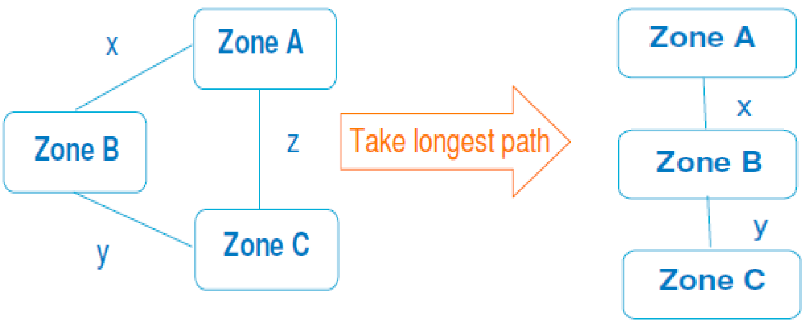
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

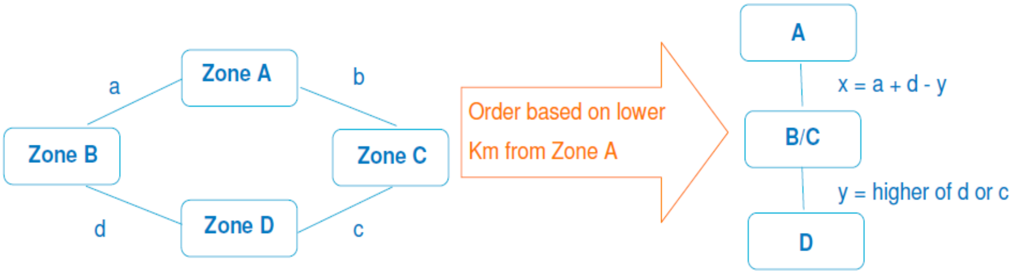
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

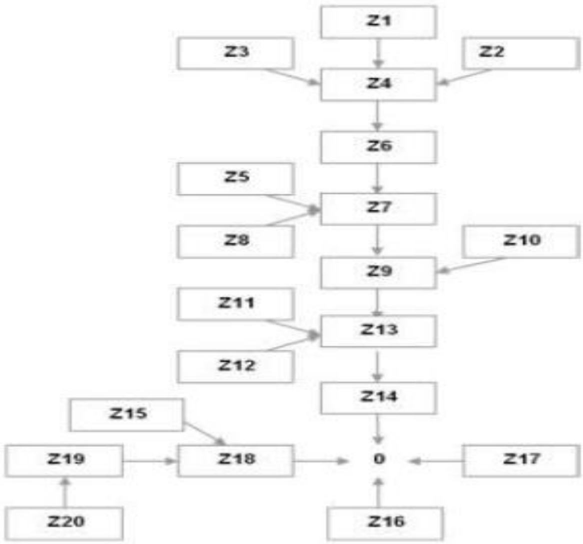
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\dfrac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and

ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.

The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'

- Having more than one delivery year
- And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}\left(EETA_{Di} \times EEVA_{Di}\right)$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14}(EETG_{Di} \times EEVG_{Di})$$

Where

ITTR<sub>EEG</sub> = Initial Revenue impact for Grandfathered Embedded Exports

EEVG<sub>Di</sub> = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.135 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:
$SLT_k$ = the offshore substation tariff for substation k
$Gen_k$ = the generation connected to offshore substation k

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**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

### Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

### Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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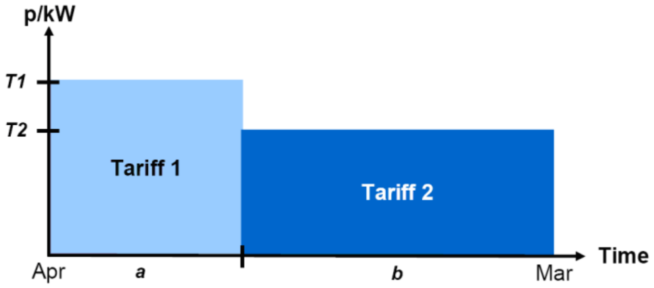
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ \ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ \ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

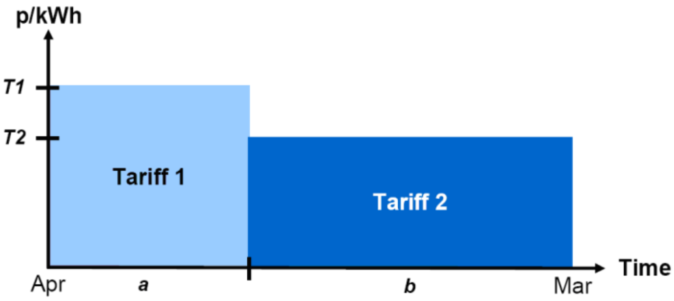
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

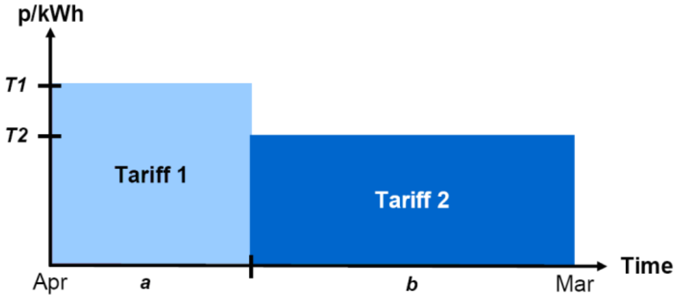
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

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**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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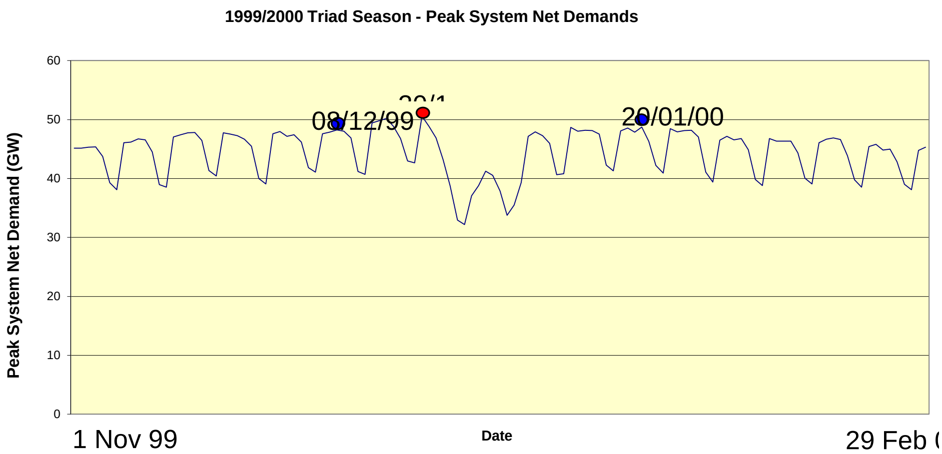


### Half-hourly metered demand charges

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

### Monthly Charges

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \textbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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£779m - £140m - -£10m = £12.98/kW

50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

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As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

= $\frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

= $\frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ····· Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ····· Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| **PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT** | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 ····· Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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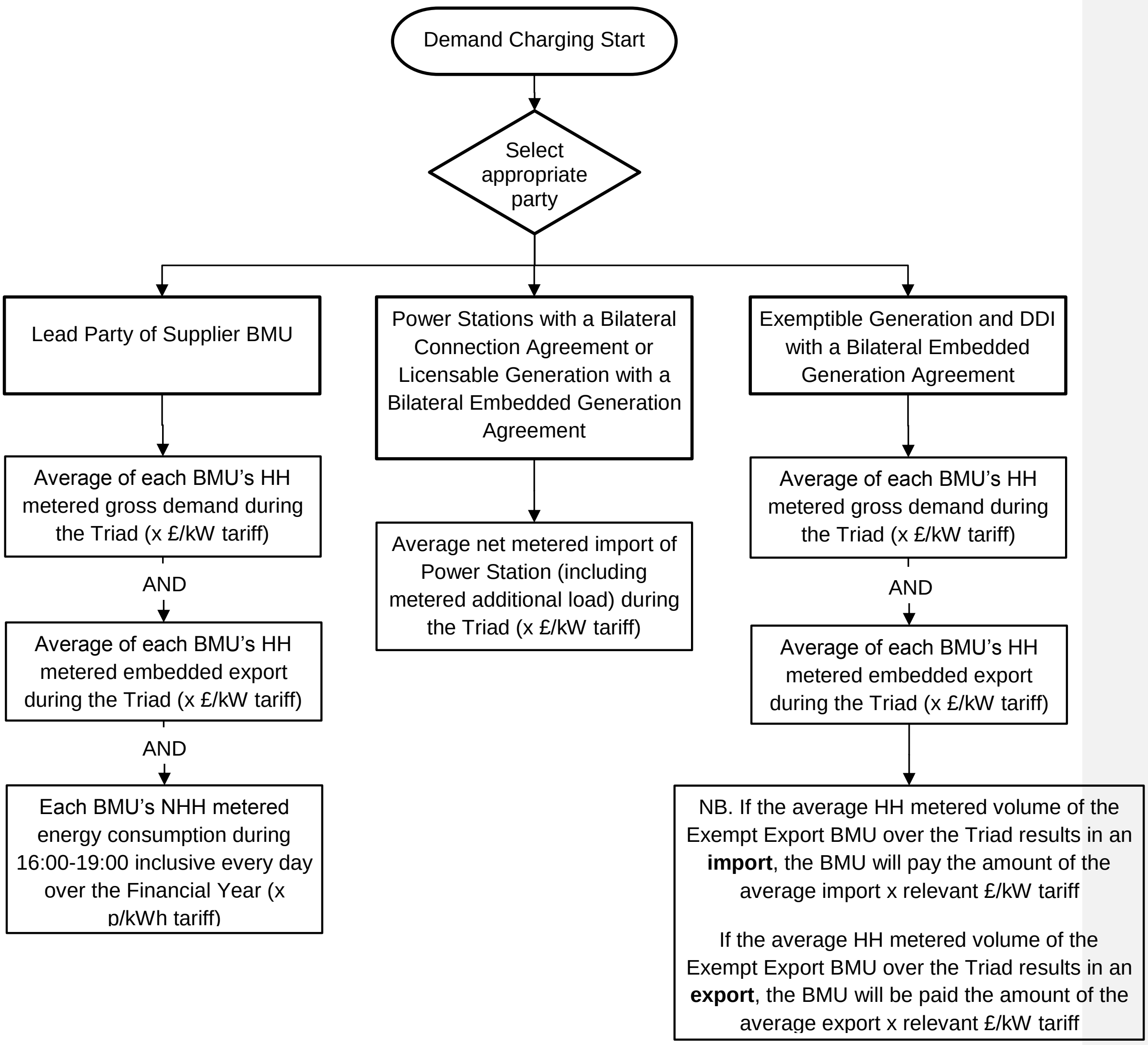
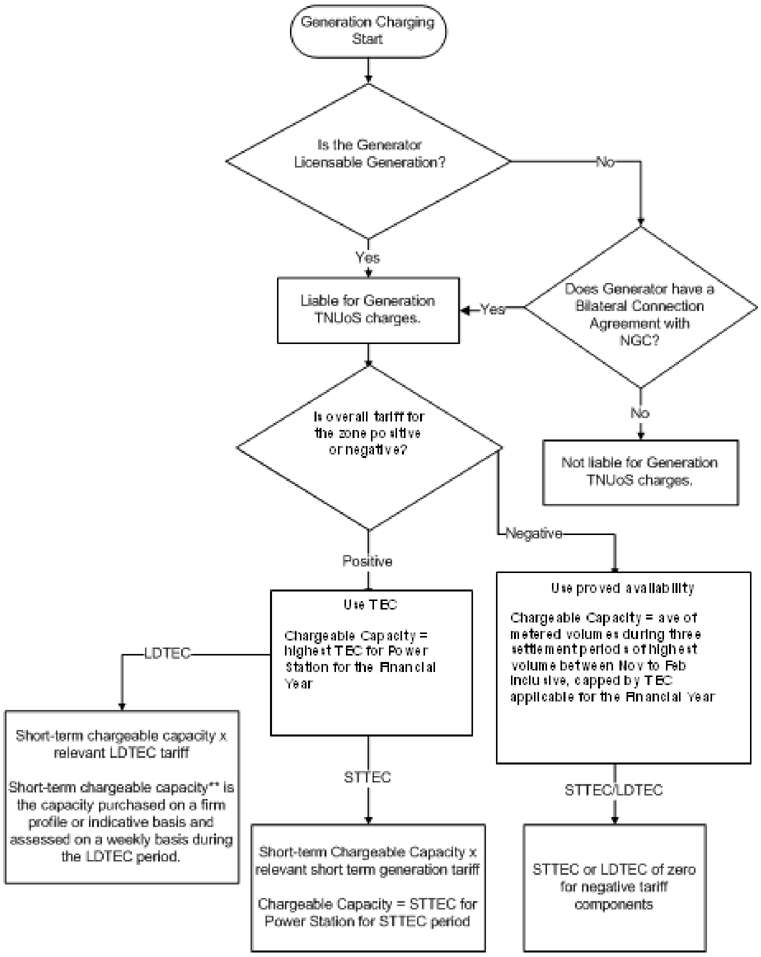



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

## Generation Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

Deleted: h

where:

T = 10,000 kW (period November 2003 to February 2004)

Deleted: h

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

Deleted: h

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

Deleted: h

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

Deleted: h

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Deleted: h

Deleted: h

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

# CMP264 WACM14

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

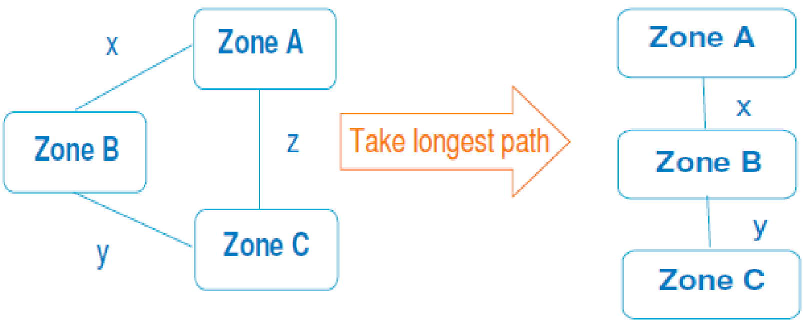
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

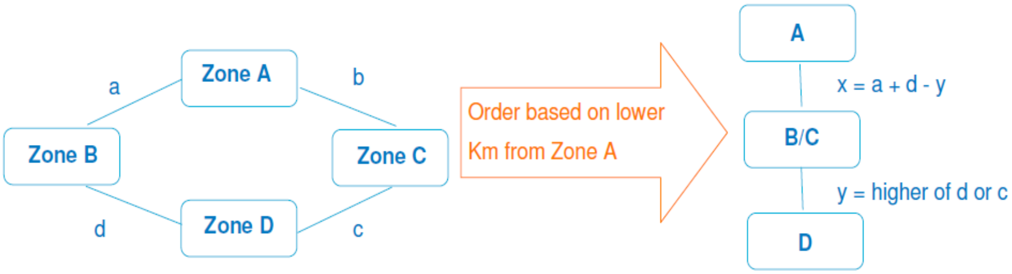
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

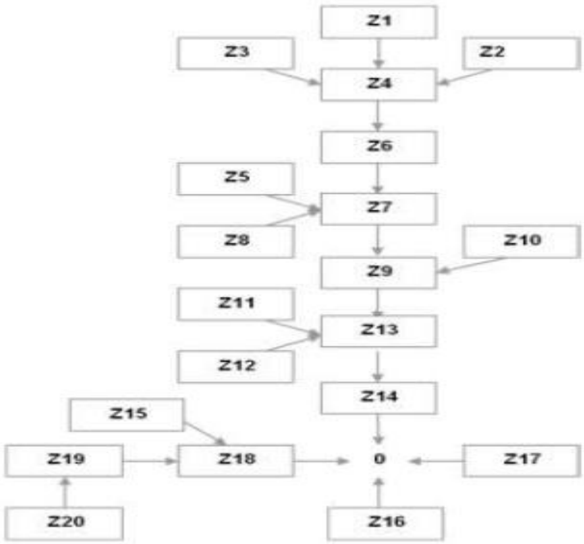
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-\left(1+WACC\right)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_{C} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = $(RT_G \times -1) + AGIC$

Where
$RT_G$ = Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

AGIC= The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
- In respect of a 'new build generating CMU'
- Having more than one delivery year
- And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}\left(EETA_{Di} \times EEVA_{Di}\right)$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

### Deriving the Final Local Tariff (£/kW)

#### *Local Circuit Tariff*

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

### Onshore Local Substation Tariff

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR_G} = \sum_{j=Gi} \mathrm{LT_{Gi}} * G_j$$

Where
LCRR$_G$ = Local Charge Revenue Recovery
G$_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.135 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:
SLT$_k$ = the offshore substation tariff for substation k
Gen$_k$ = the generation connected to offshore substation k

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**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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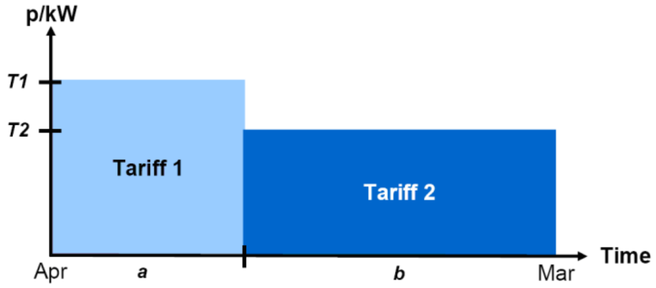
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

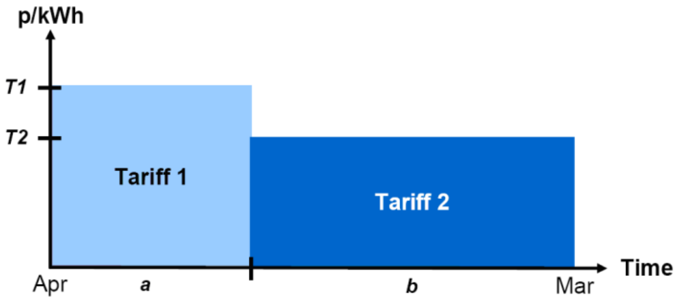
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

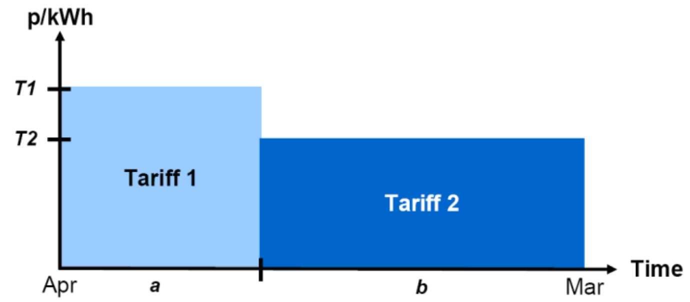
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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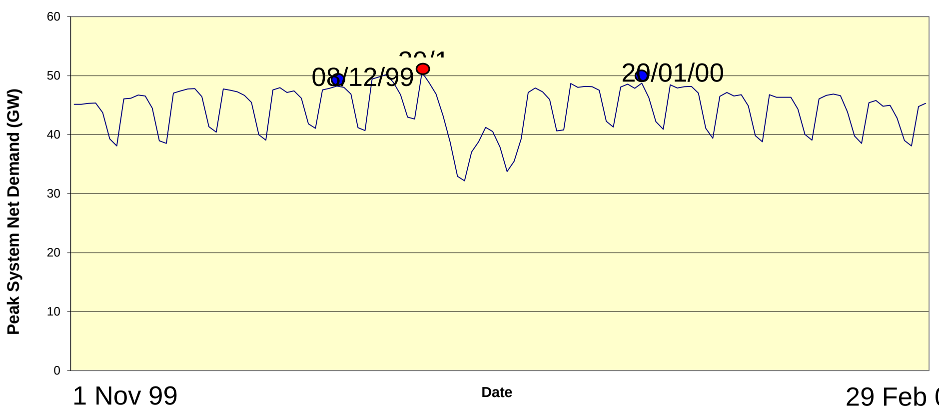
1999/2000 Triad Season - Peak System Net Demands




**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

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14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

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- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

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b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50,000MW} = £12.98/kW$$

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¶
£779m - £140m - -£10m = £12.98/kW¶
50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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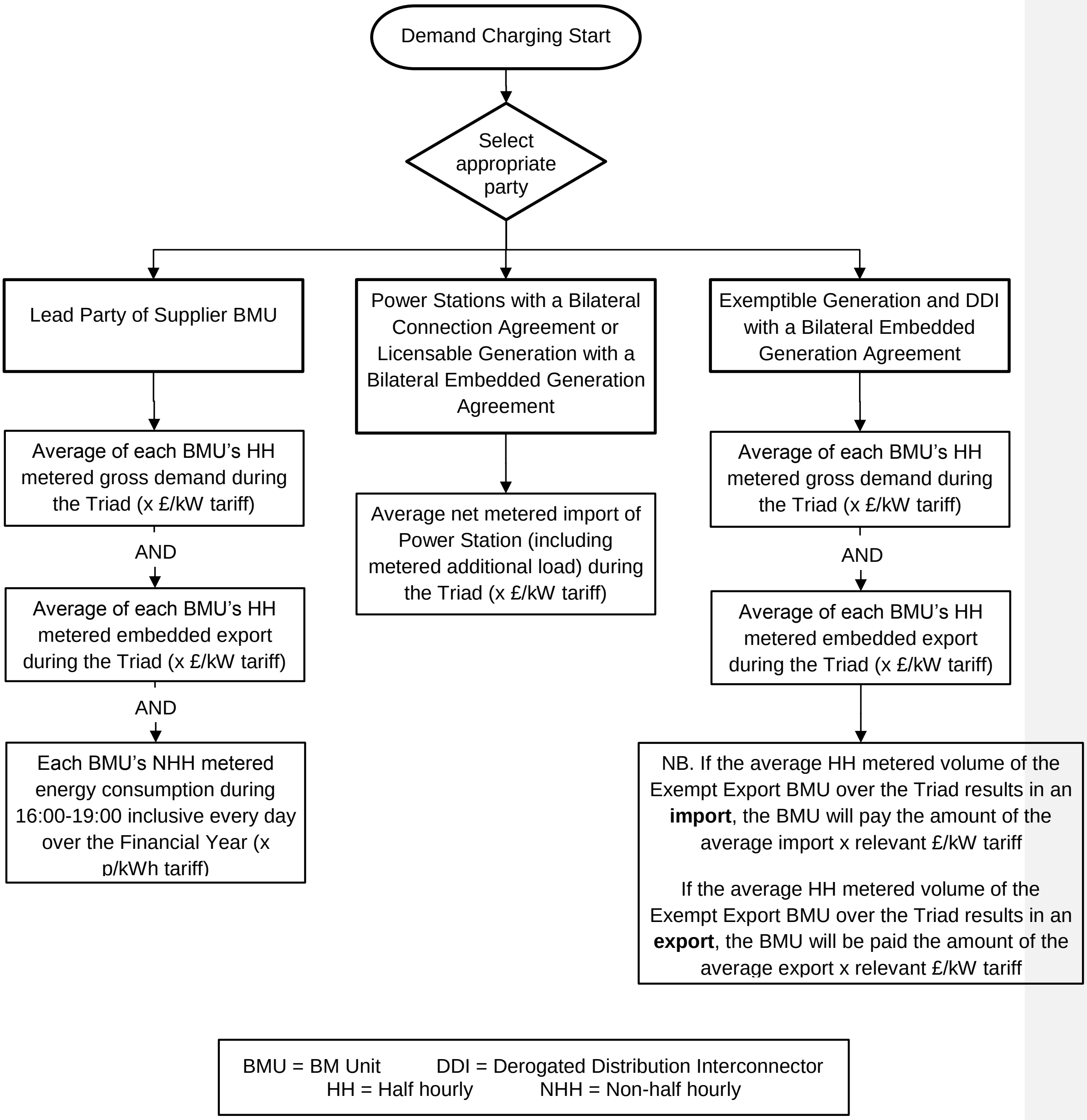
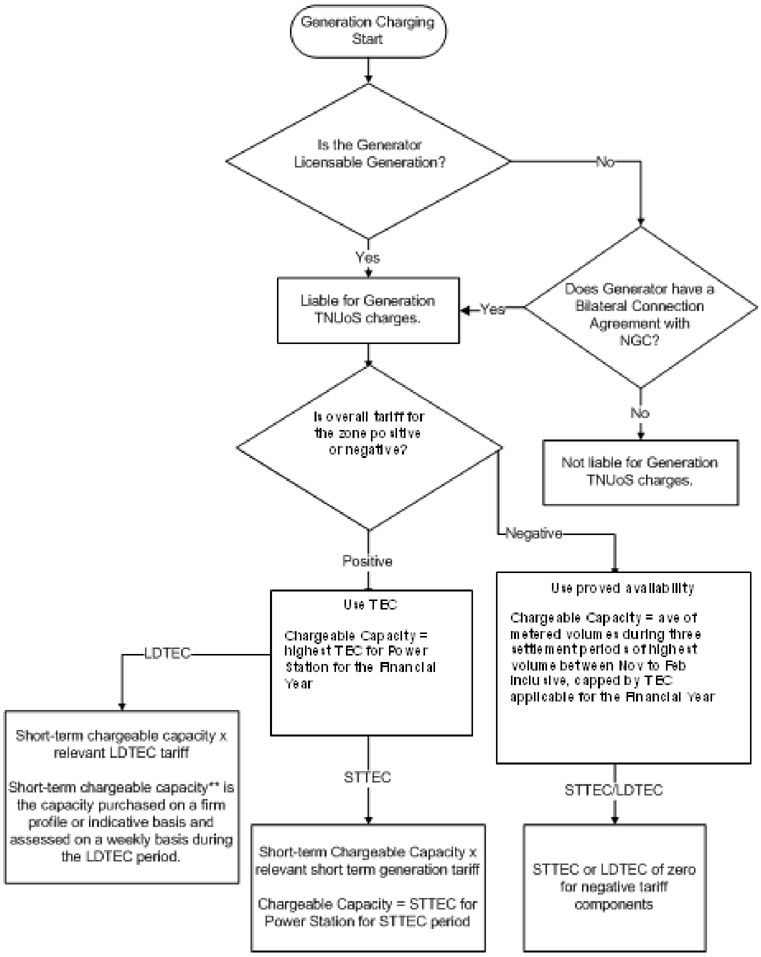


Generation
Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

# CMP264 WACM15

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_{b} - ZIkm_{a}$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

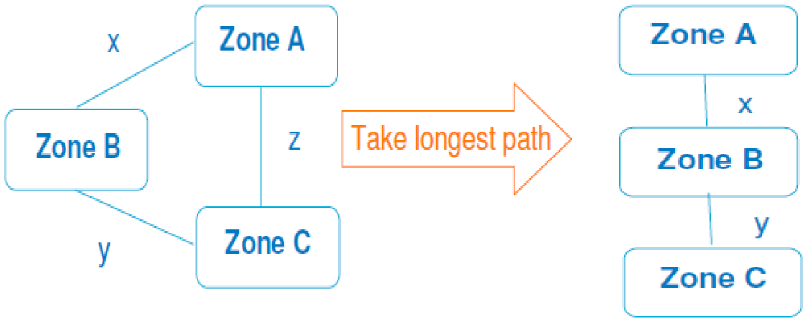
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

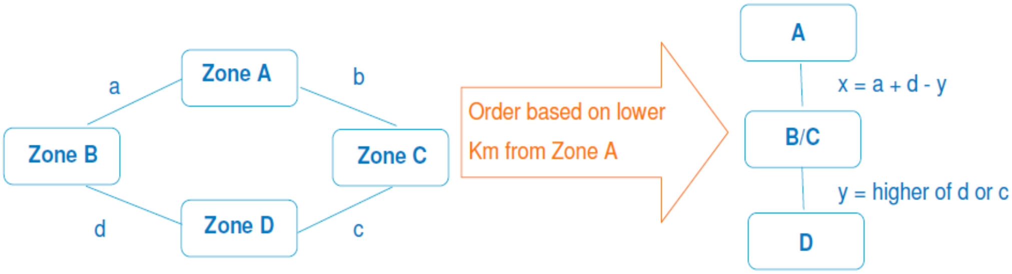
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

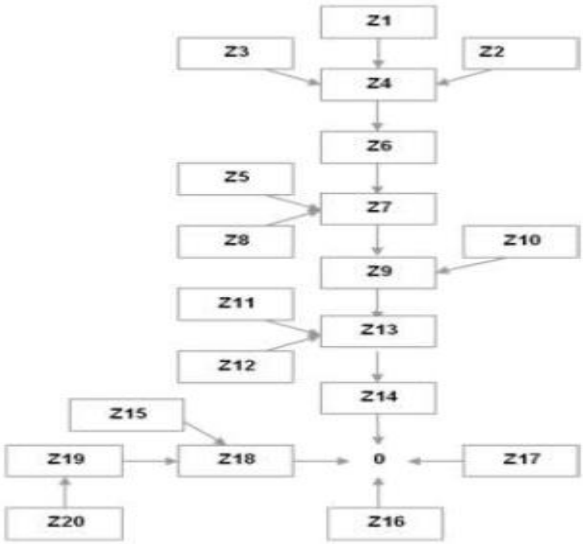
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\dfrac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and

ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:

$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:

$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:

$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A) \}$

and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

## TNUoS Embedded Export Tariffs

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = $ABs\ (Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'
  - Having more than one delivery year
  - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}(EETA_{Di} \times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14}(EETG_{Di} \times EEVG_{Di})$$

Where

ITTR$_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

EEVG$_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under |

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where
$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW
$ET_{EEGI}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEAi}$$
$$FT_{EEGi} = ET_{EEGi}$$

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14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.** **Deleted:** 137

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.* **Deleted:** 138

14.15.145 New Grid Supply Points will be classified into zones on the following basis: **Deleted:** 139

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use. **Deleted:** 140

14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**. **Deleted:** 141

14.15.148 The factors which will affect the level of TNUoS charges from year to year include-; **Deleted:** 142

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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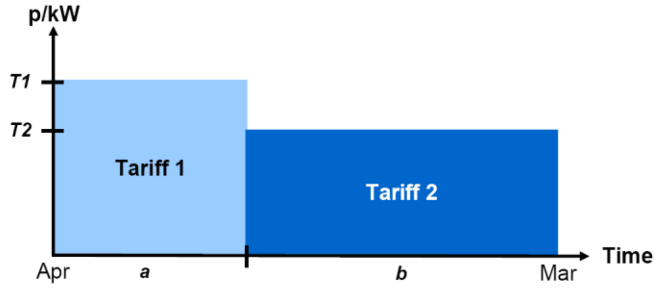
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

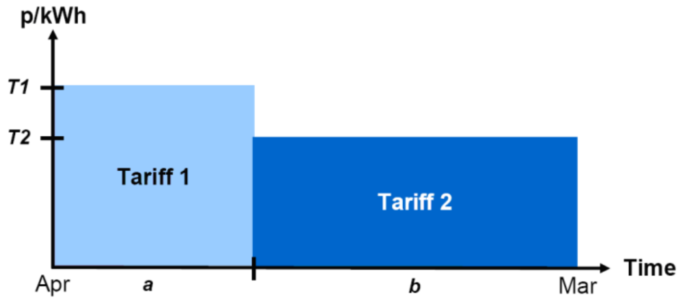
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \begin{array}{c} Chargeable\ Embedded \\ Export\ Capacity \end{array} \times \left( \frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12} \right)$$

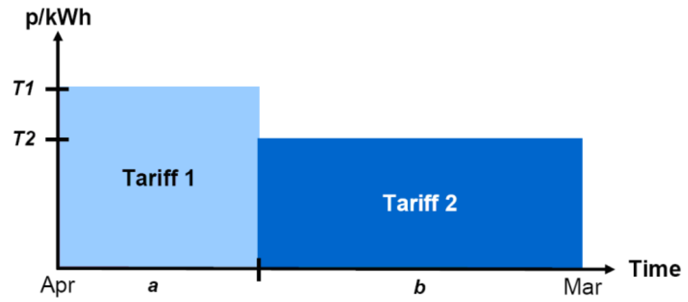
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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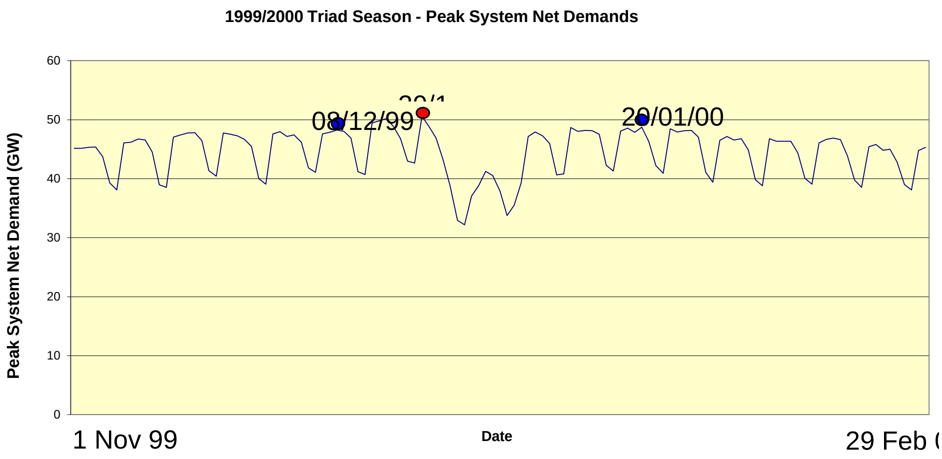


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

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14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} \times £10.07/\text{MWkm} \times 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**

1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

**Deleted:** $\frac{£779m - £130m}{50000MW} =$

¶

£779m - £140m - -£10m =

£12.98/kW¶

50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= (17,000,000kWh - 18,000,000kWh) x 1.20p/kWh / 100

= -1,000,000kWh x 1.20p/kWh / 100

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

| | |
|---|---|
| Final HH Gross Demand Reconciliation Charge | = (9,500kW - 9,000kW) x £10.00/kW<br>= £5,000 |
| Final HH Embedded Export Reconciliation Charge | = (-550kW - -500kW) x £5.00/kW<br>= -£250 |
| Final NHH Reconciliation Charge | = (16,700,000kWh – 17,000,000kWh) x 1.20p/kWh / 100<br>= -£3,600 |

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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# 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

## Demand Charges

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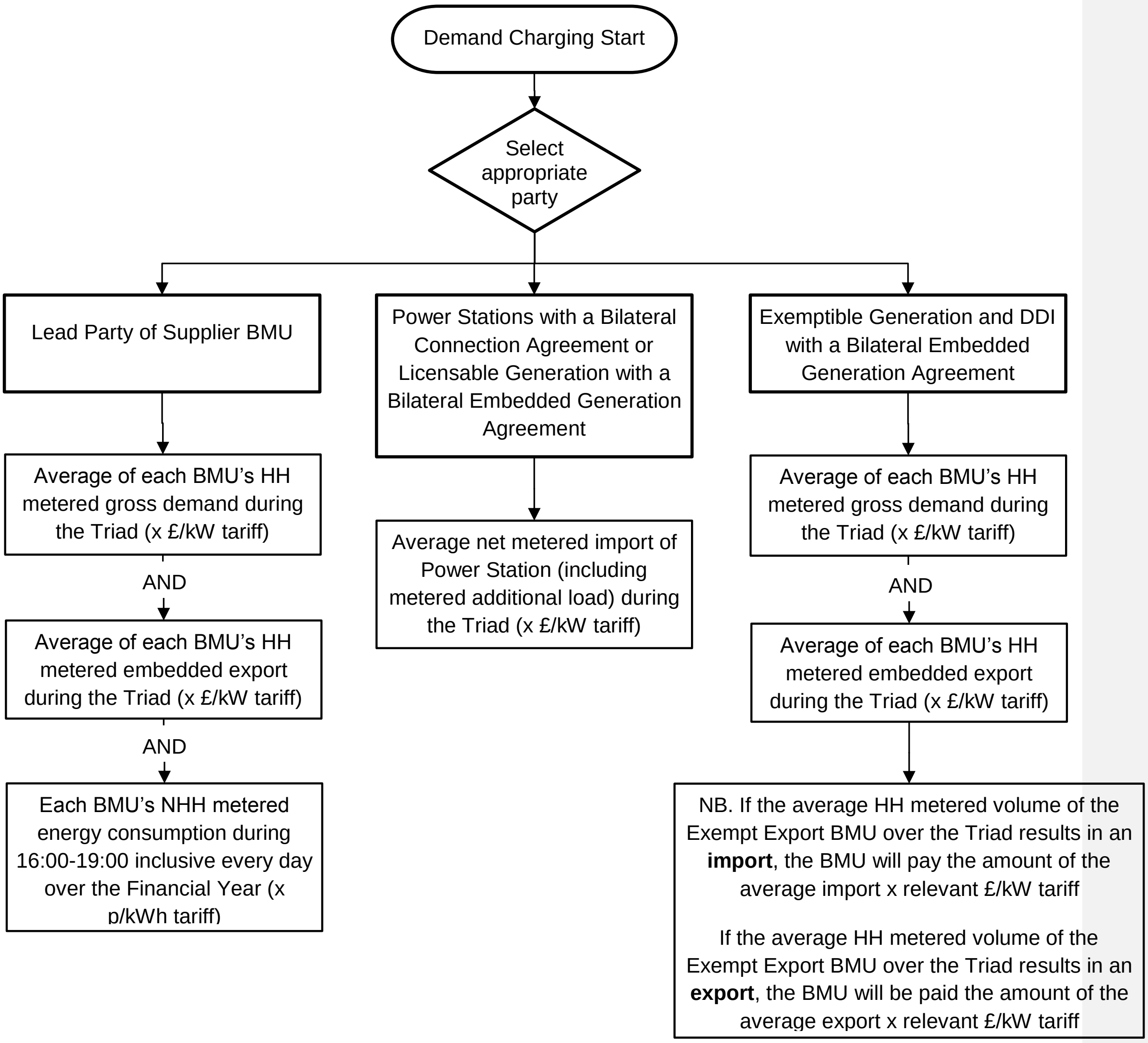
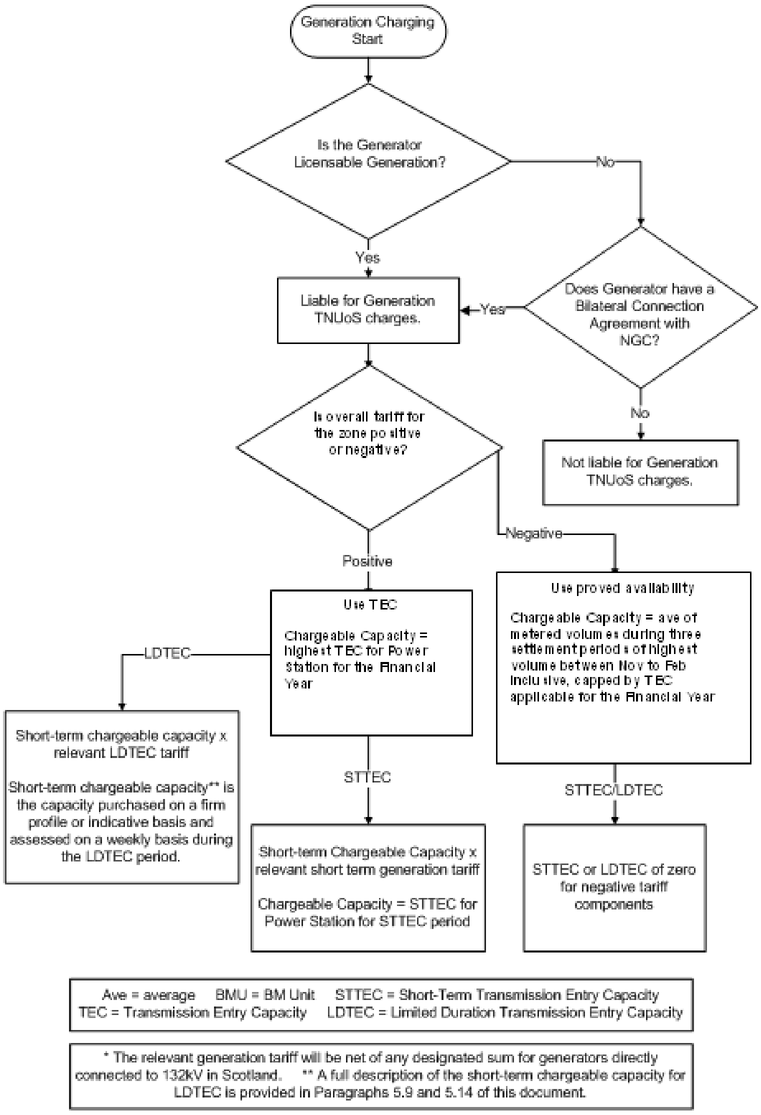



BMU = BM Unit　　DDI = Derogated Distribution Interconnector
HH = Half hourly　　NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP264 WACM16

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

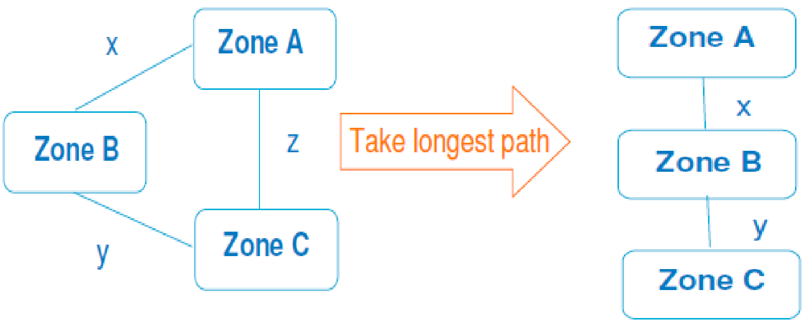
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

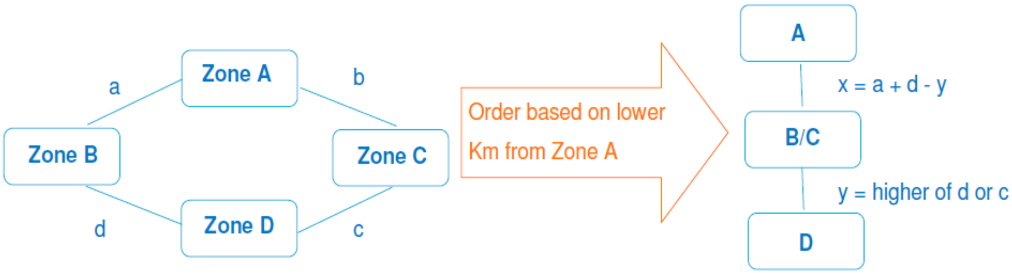
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

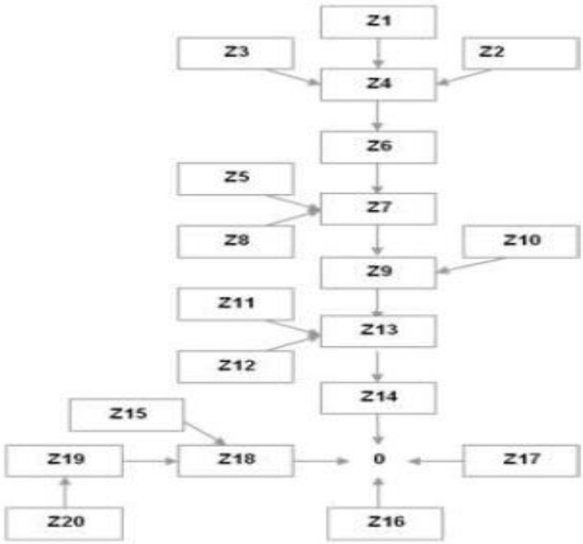
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner’s reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = AGIC + (£18.50 in April 2019 prices; indexed each year by the RPI formula set out in 14.3.6).

Where
AGIC= The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or

- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'
  - Having more than one delivery year
  - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ generation = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ generation = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}(EETA_{Di} \times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_G = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_j$$

Where
LCRR$_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.135 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:
$SLT_k$ = the offshore substation tariff for substation k
$Gen_k$ = the generation connected to offshore substation k

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**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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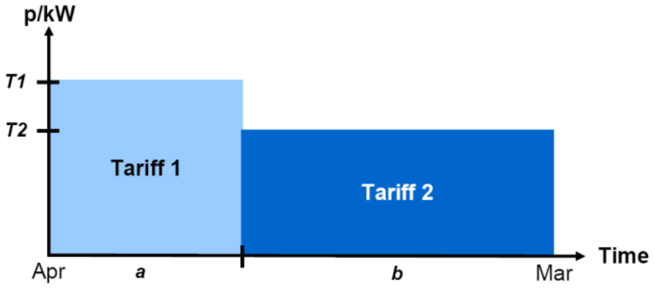
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

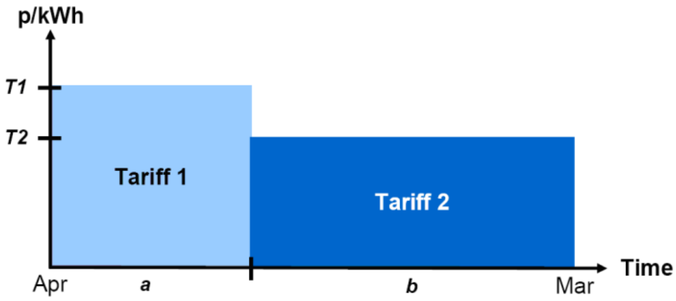
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

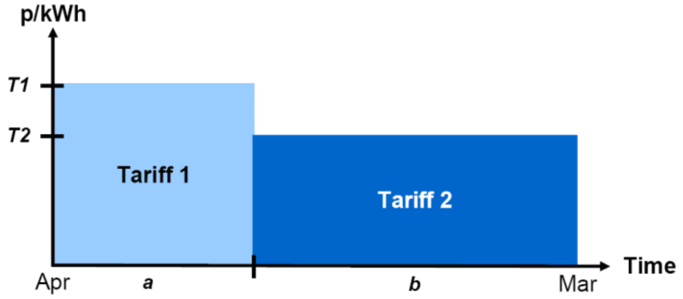
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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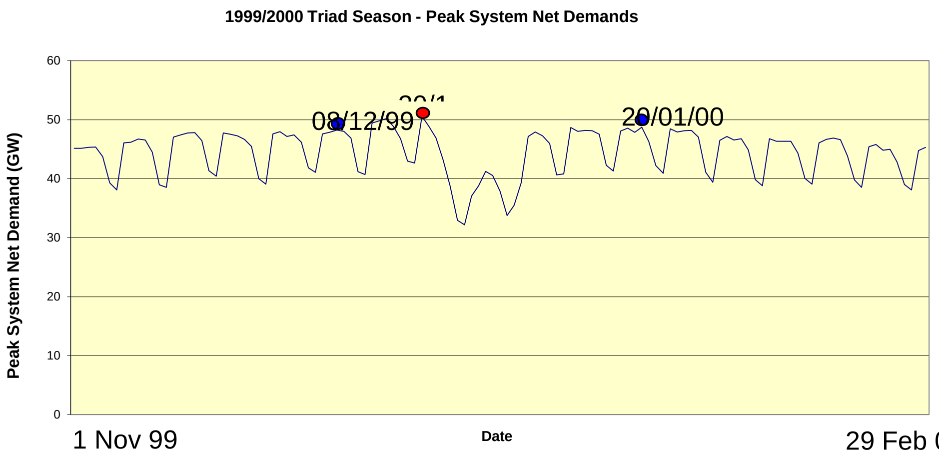


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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£779m - £140m - -£10m = £12.98/kW

50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:



**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = (NHHC$_A$ - NHHC$_F$) x p/kWh Tariff

100

= (17,000,000kWh - 18,000,000kWh) x 1.20p/kWh

100

= -1,000,000kWh x 1.20p/kWh
100

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = (16,700,000kWh – 17,000,000kWh) x 1.20p/kWh
100
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**HHD$_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
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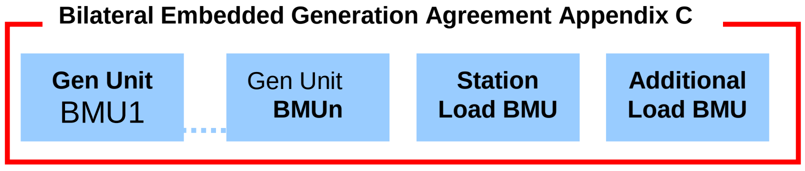
<tr><td colspan="2">
</td></tr>
<tr><td>Demand Charges<br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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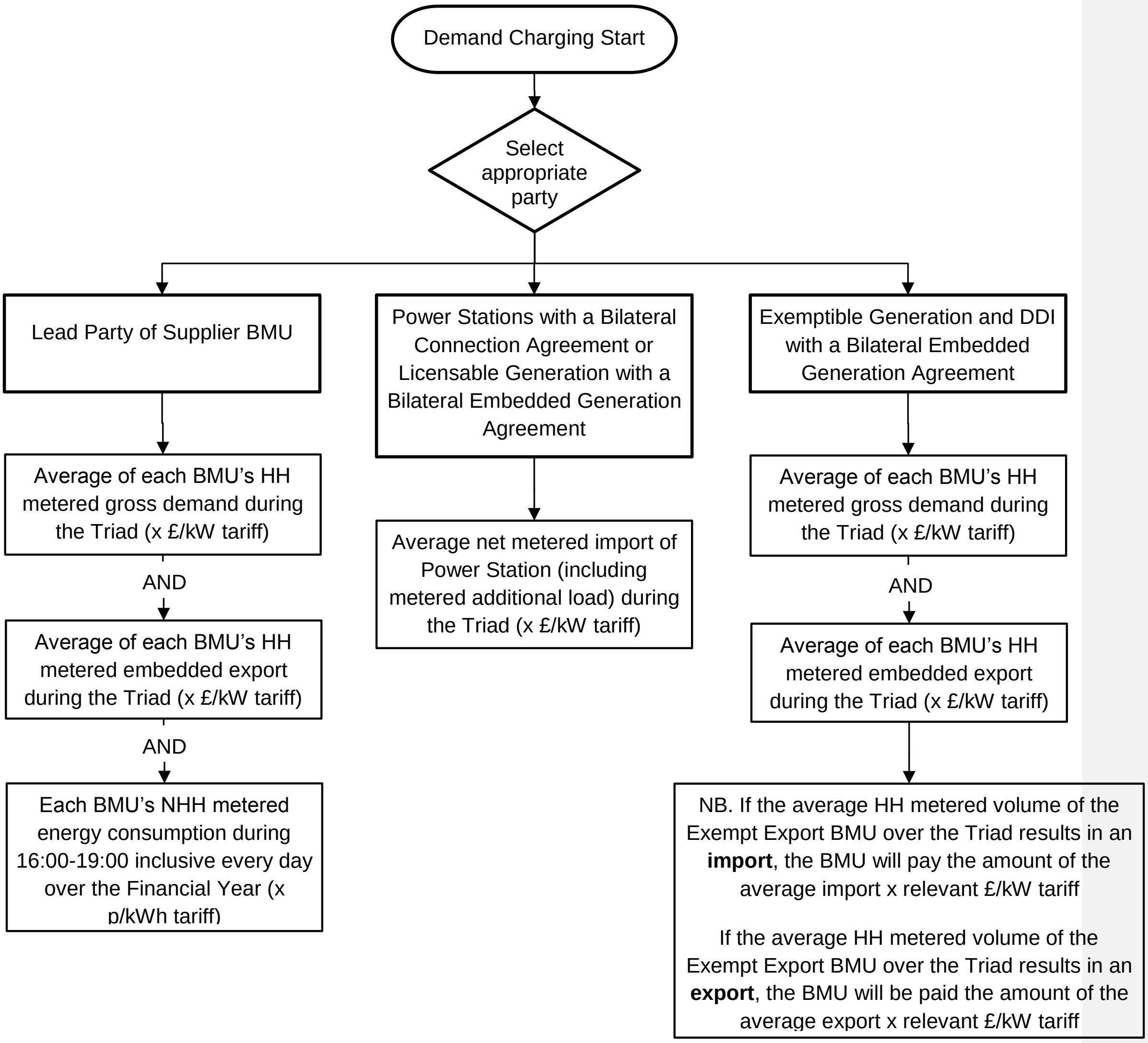
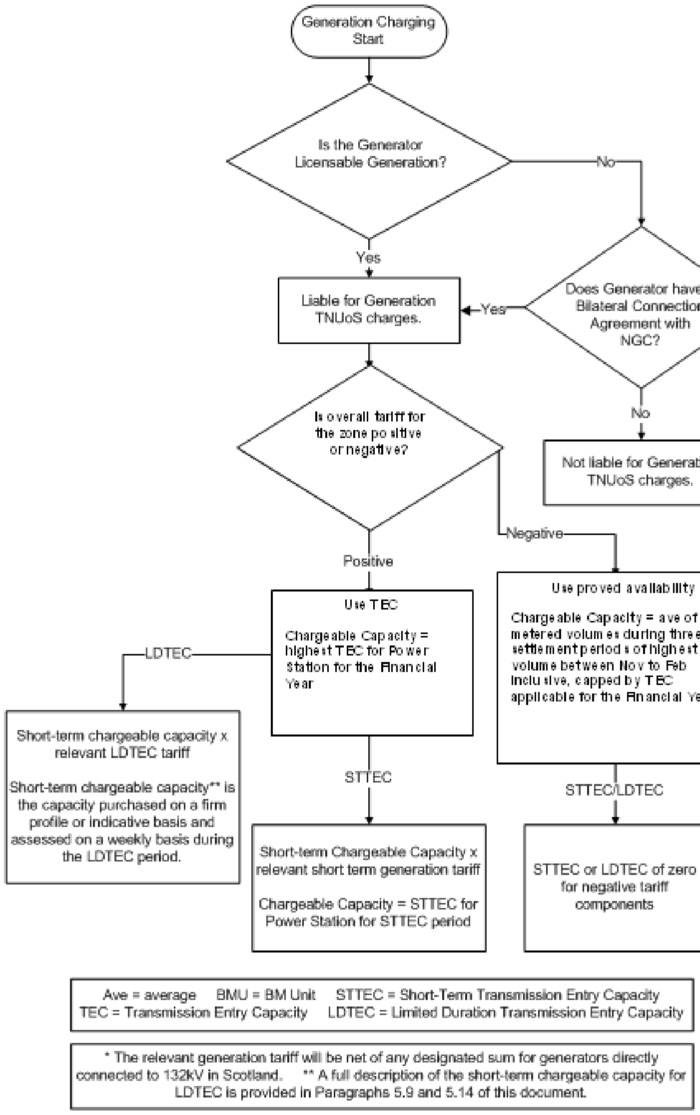



BMU = BM Unit    DDI = Derogated Distribution Interconnector
HH = Half hourly    NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP264 WACM17

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

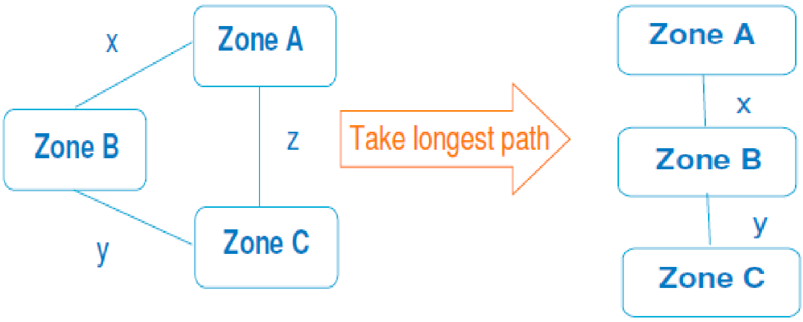
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

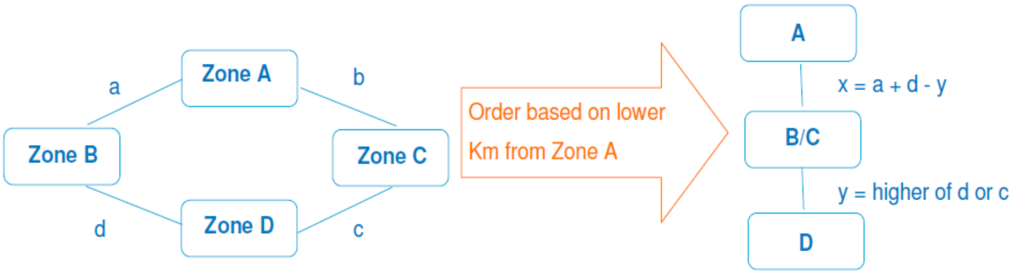
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

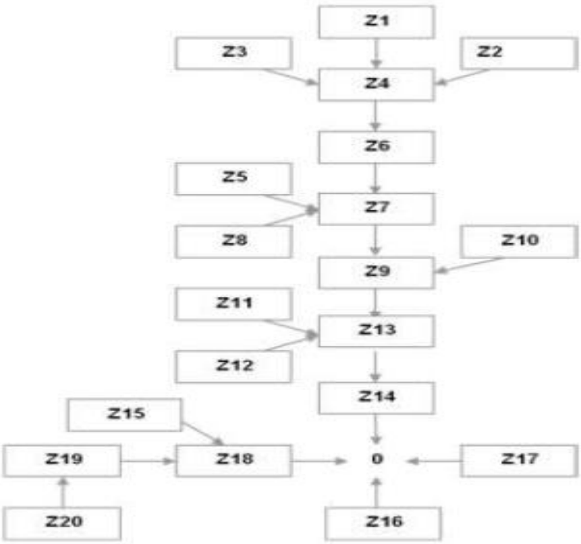
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$
$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = £32.30 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'
  - Having more than one delivery year
  - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS}\times G_{Gi}\times ALF\right)=ITRR_{G\,YRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}(EETA_{Di}\times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG}=\sum_{Di=1}^{14}(EETG_{Di}\times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |

| | | | | |
|---|---|---|---|---|
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore

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Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore\\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

$SLT_k$ = the offshore substation tariff for substation k

$Gen_k$ = the generation connected to offshore substation k

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

Deleted: $RT_D = \frac{(p \times TR\ldots}{}$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGI}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} *100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Gross Demand Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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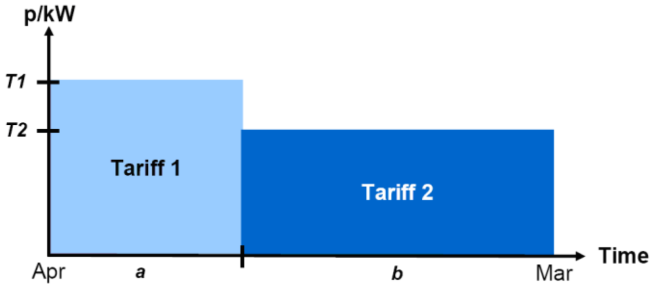
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ \ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ \ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

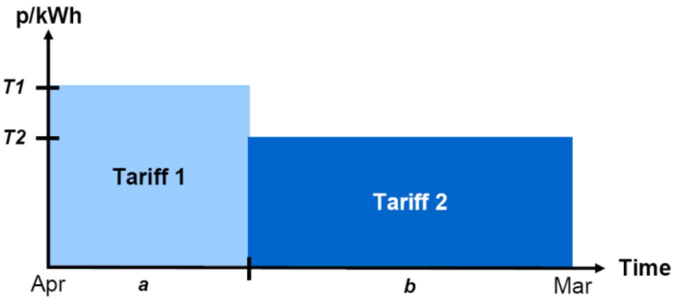
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

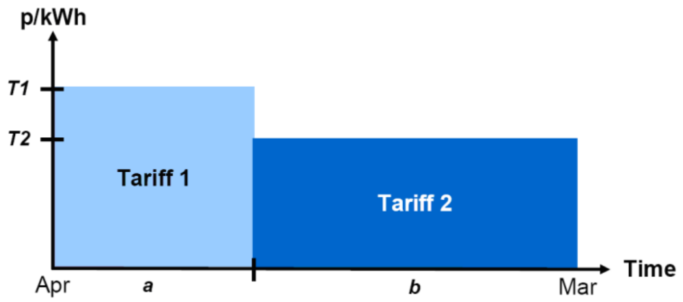
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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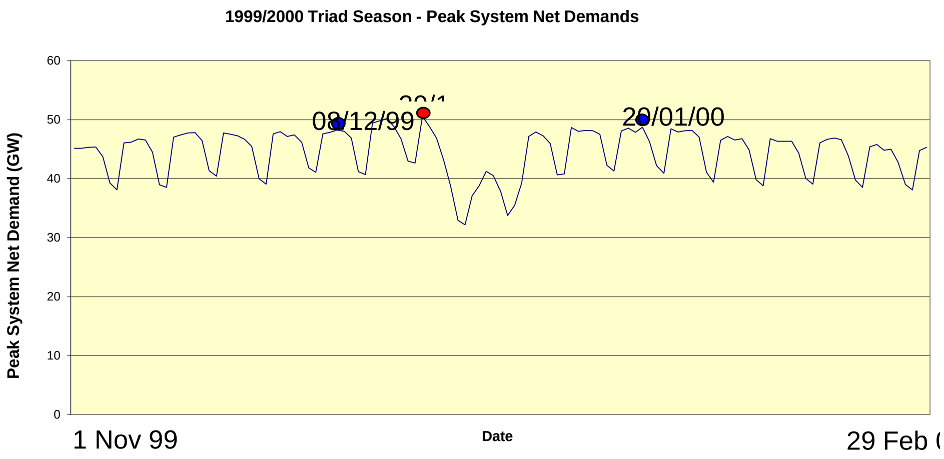


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \textbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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£779m - £140m - -£10m = £12.98/kW¶
50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A – HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:



**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh - 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

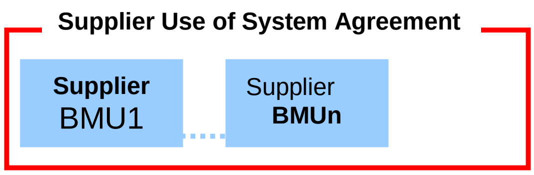
**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

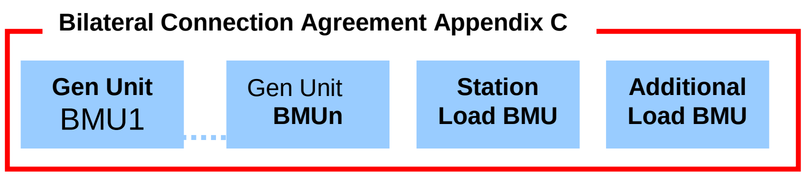
In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.14.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| **PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT** | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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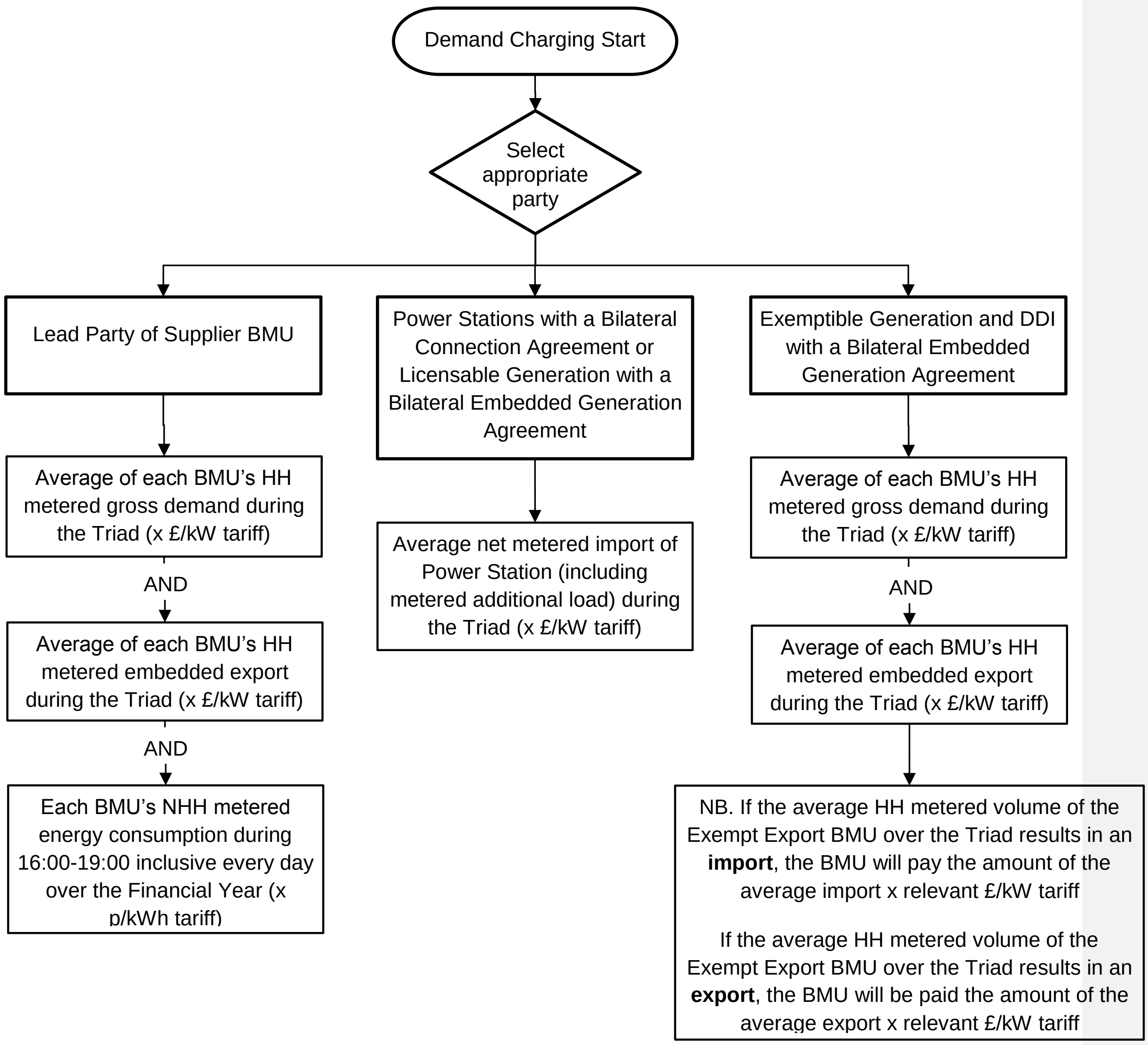
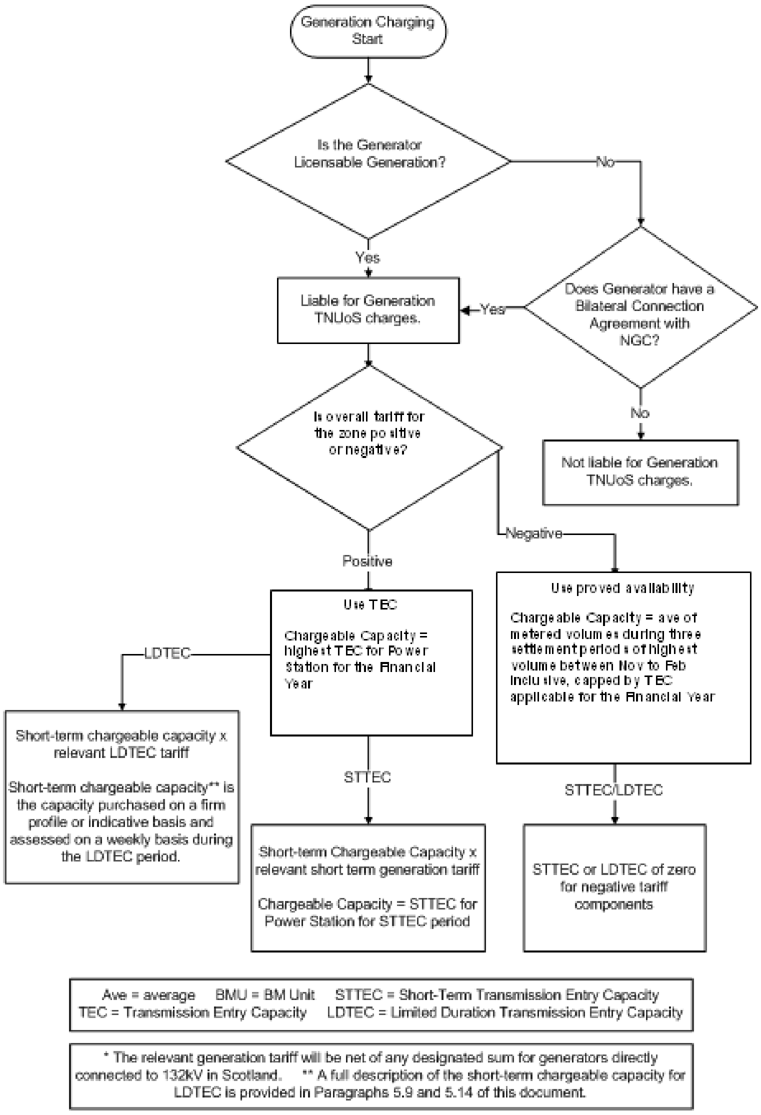



BMU = BM Unit    DDI = Derogated Distribution Interconnector
HH = Half hourly    NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

Deleted: h

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

Deleted: h

Deleted: h

Deleted: h

Deleted: h

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP264 WACM18

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

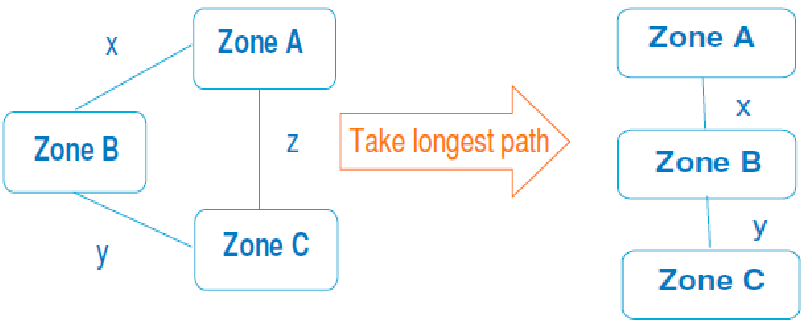
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

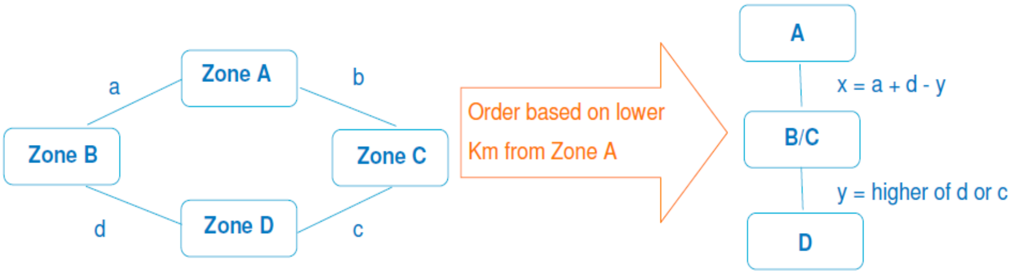
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

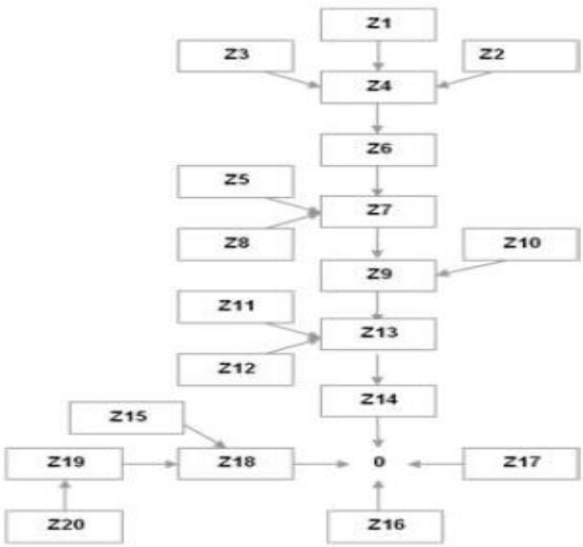
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner’s reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX:

$$AEX = \frac{(p \times TRR) - OC - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14}(D_{Di} + EEV_{Di})}$$

Where
AEX= Residual Tariff for embedded Affected Embedded Exports
P = Proportion of revenue to be recovered from demand
OC = Offshore Costs paid by demand
$ITRR_{DPS}$ = Peak Security Initial Transport Revenue Recovery for demand
$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for demand
$D_{Di}$ = Total forecast Metered Triad Gross Demand for each demand zone $EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
- In respect of a 'new build generating CMU'

- Having more than one delivery year
- And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}(EETA_{Di}\times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

| | | |
|---|---|---|
| | $ITTR_{EEG}$ | = Initial Revenue impact for Grandfathered Embedded Exports |
| | $EEVG_{Di}$ | = Forecast Grandfathered Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_{k}$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\,offshore\\substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

| | | |
|---|---|---|
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

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$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

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14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

Deleted: $Annual\ Liability_{D}$

$$Annual\ Liability_{Demand} = \underline{\text{Chargeable Gross Demand Capacity}} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

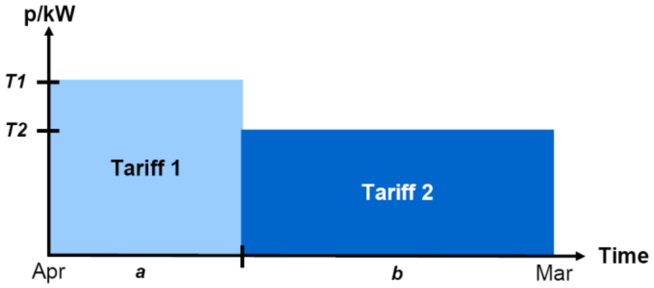
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

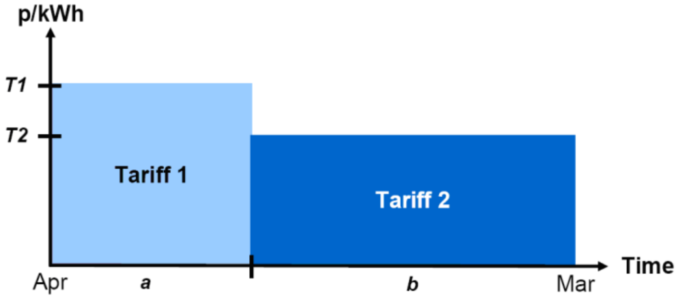
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

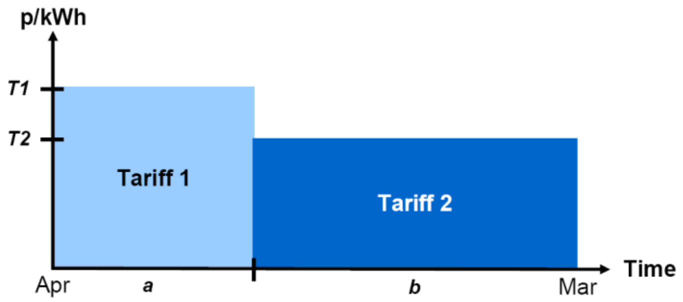
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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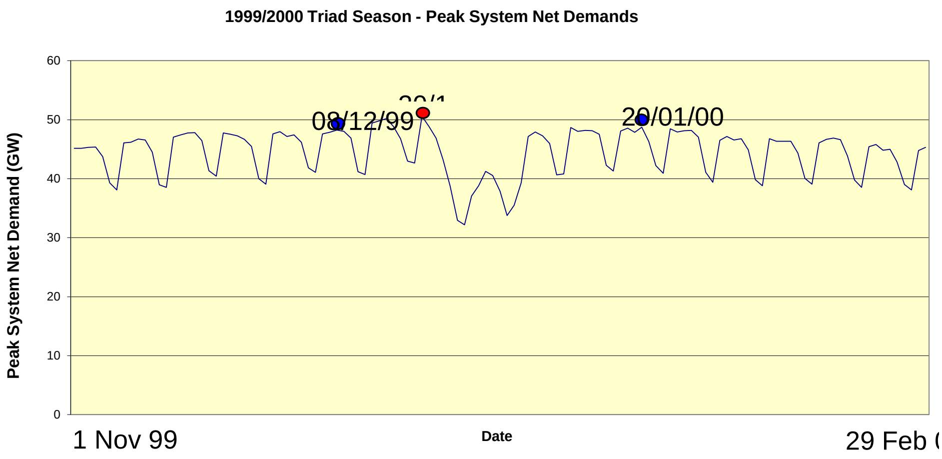


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \underline{\mathbf{£3.45/kW}}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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¶
£779m - £140m - -£10m = £12.98/kW¶
50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><th colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</th></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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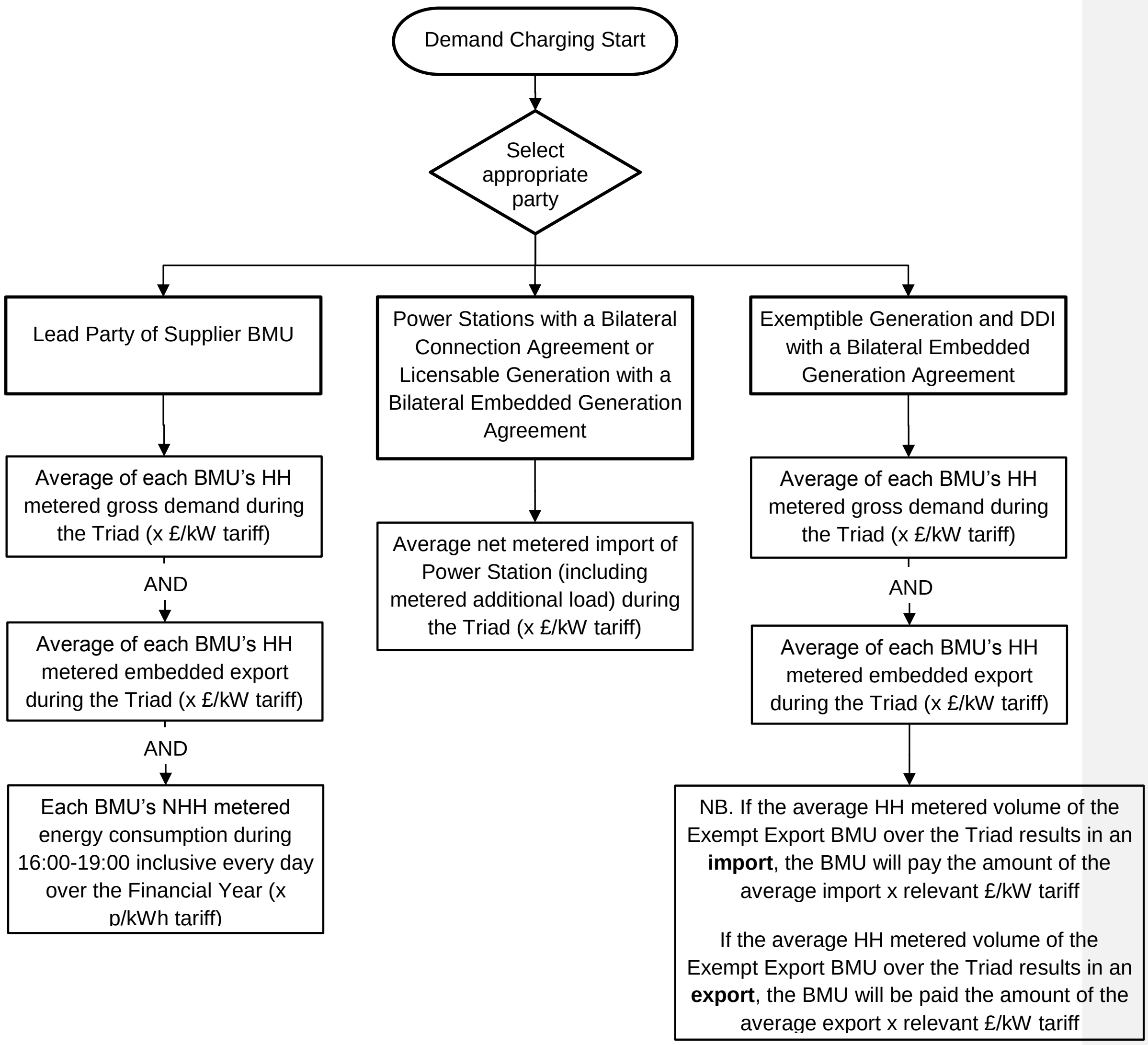
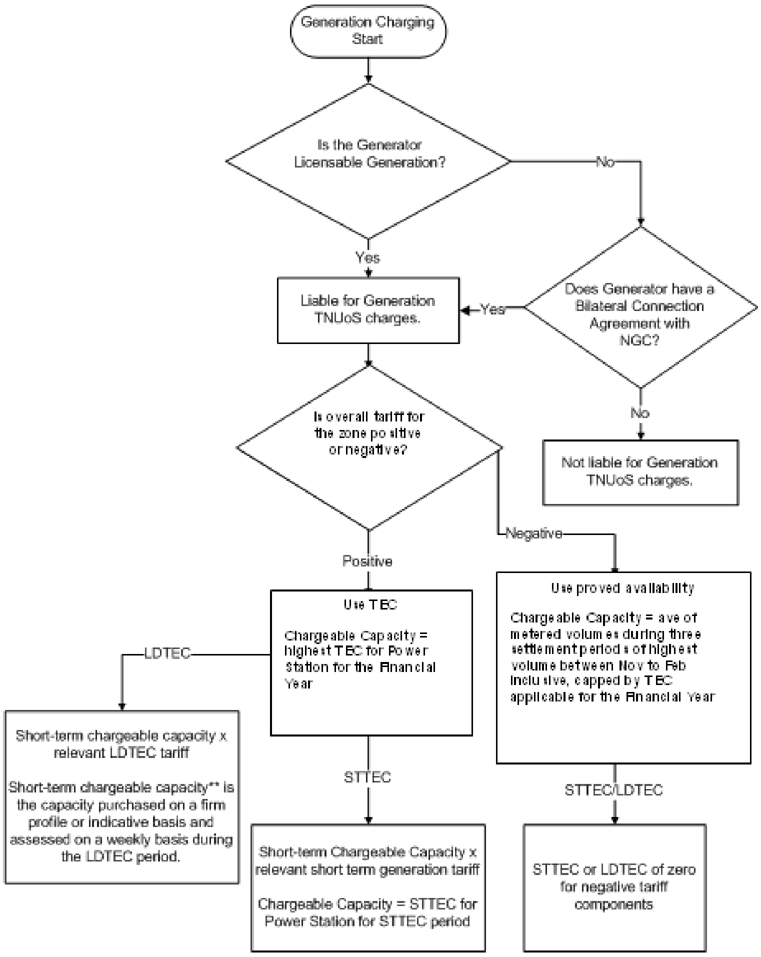



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

## Generation Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

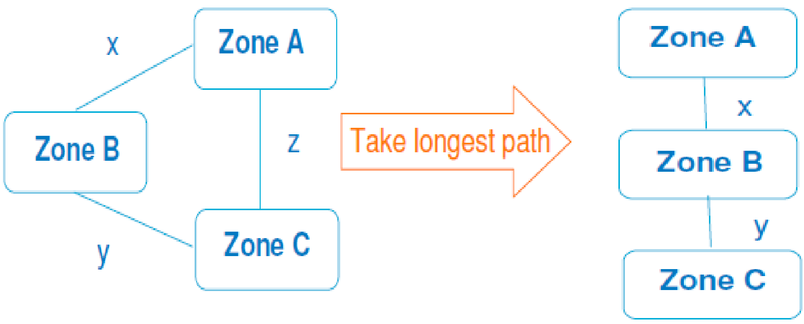
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

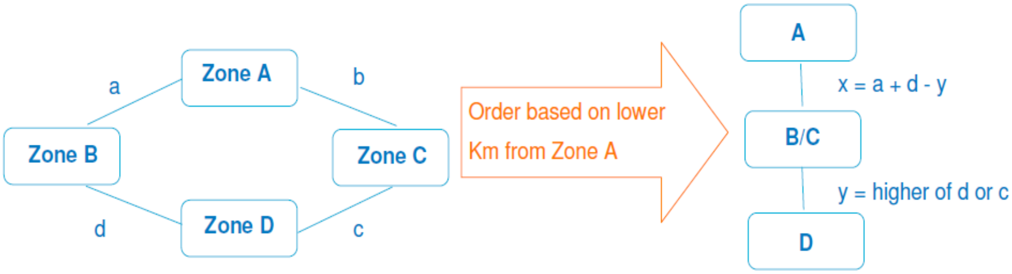
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

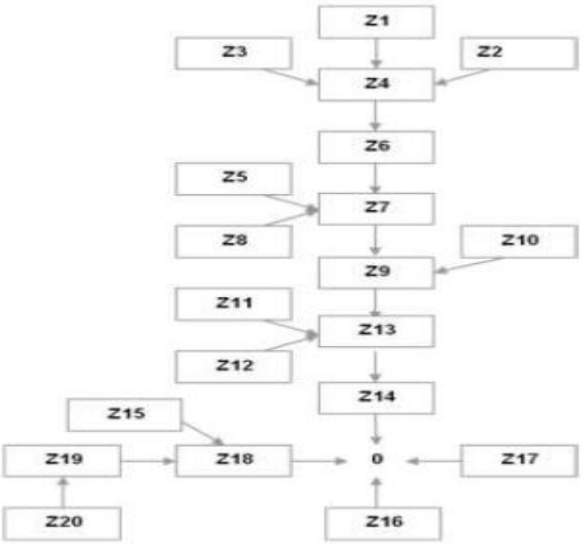
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\dfrac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = £0

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation has certification in accordance with Engineering Recommendation G59 (or a relevant replacement of G59 certification) before 01/07/2017.

G59 certification requirements are published by The Energy Networks Association.

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS}\times G_{Gi}\times F_{PS}\right)=ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type

n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS}\times D_{Di}\right)=ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS}\times G_{Gi}\times ALF\right)=ITRR_{G\,YRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}(EETA_{Di} \times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14}(EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff: **Deleted:** 116

$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors: **Deleted:** 117

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are: **Deleted:** 118

| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period. **Deleted:** 119

14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components: **Deleted:** 120

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

$ELT_{Gi}$ = $LT_{Gi}$

Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{G} = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_{j}$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the



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relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITRR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

### Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where
$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW
$ET_{EEGI}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

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14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore,
$$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.

- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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**Stability & Predictability of TNUoS tariffs**

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \begin{matrix}Chargeable\ Gross\\ Demand\ Capacity\end{matrix} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

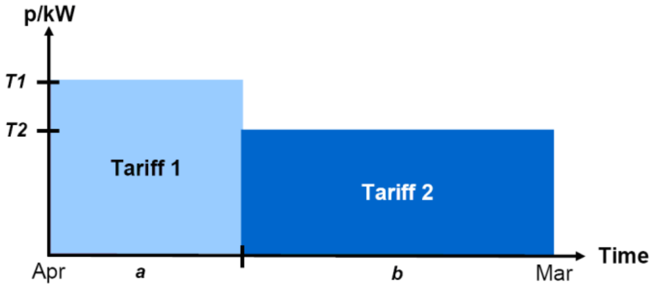
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

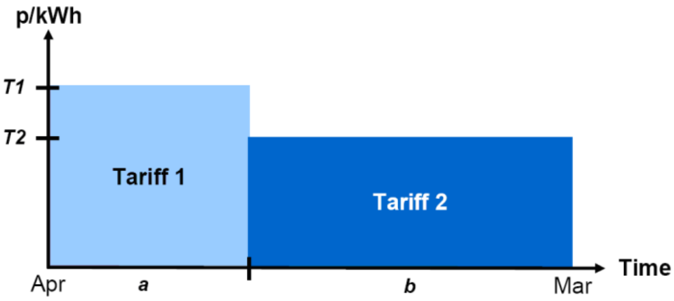
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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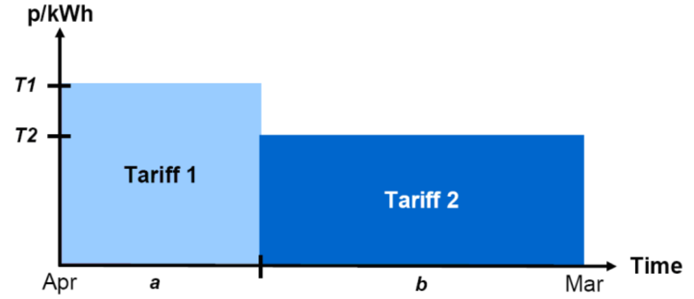
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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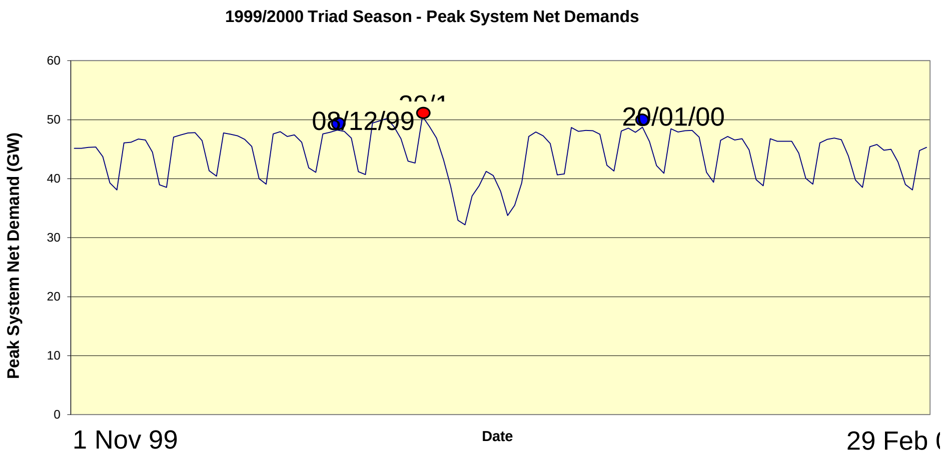


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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£779m - £140m - -£10m = £12.98/kW

50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A - HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17,000,000kWh - 18,000,000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1,000,000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16,700,000kWh – 17,000,000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | | | |
|---|---|---|---|
| **Bilateral Embedded Generation Agreement Appendix C** | | | |
| **Gen Unit** BMU1 | Gen Unit **BMUn** | **Station Load BMU** | **Additional Load BMU** |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** | | |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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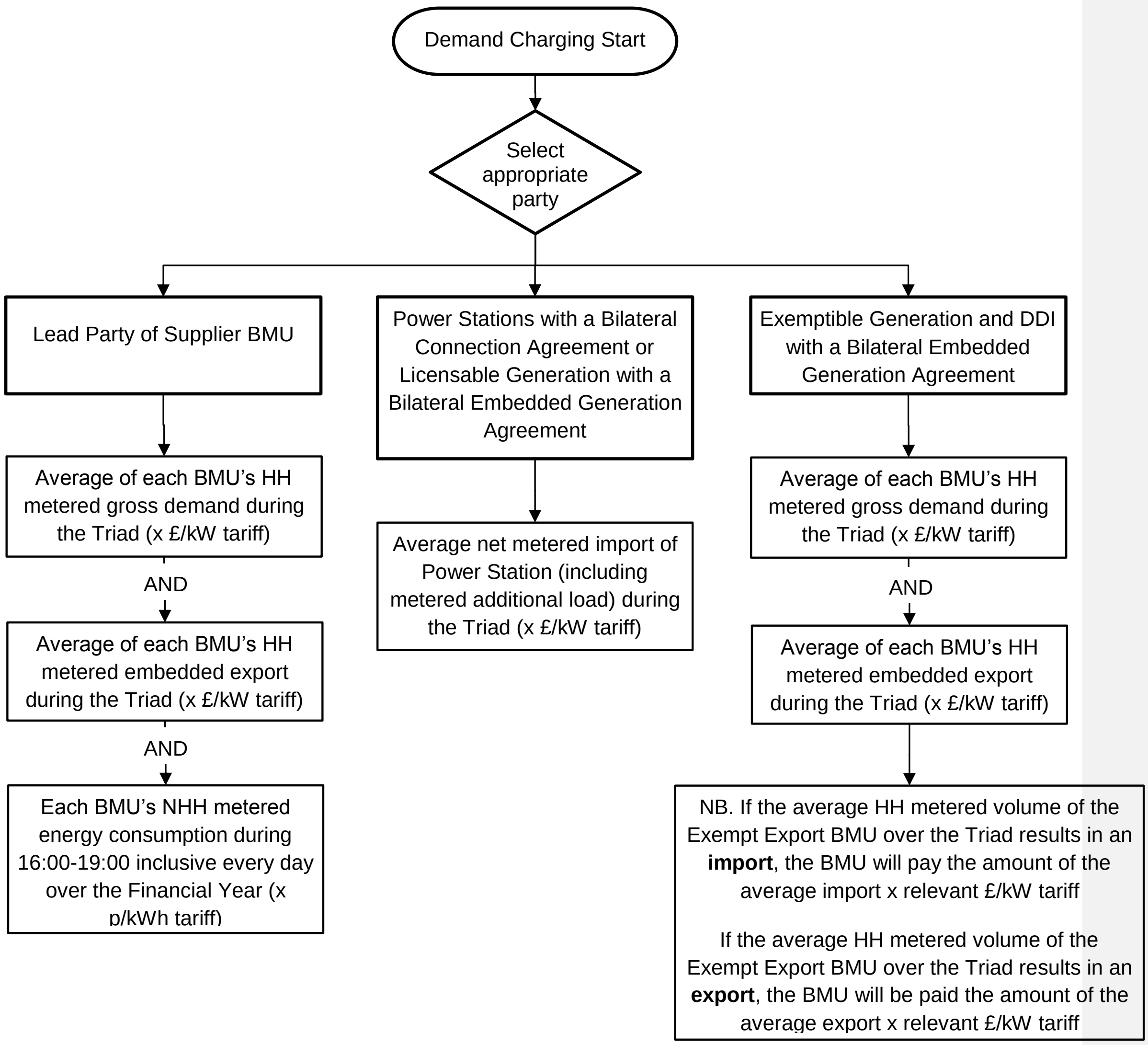
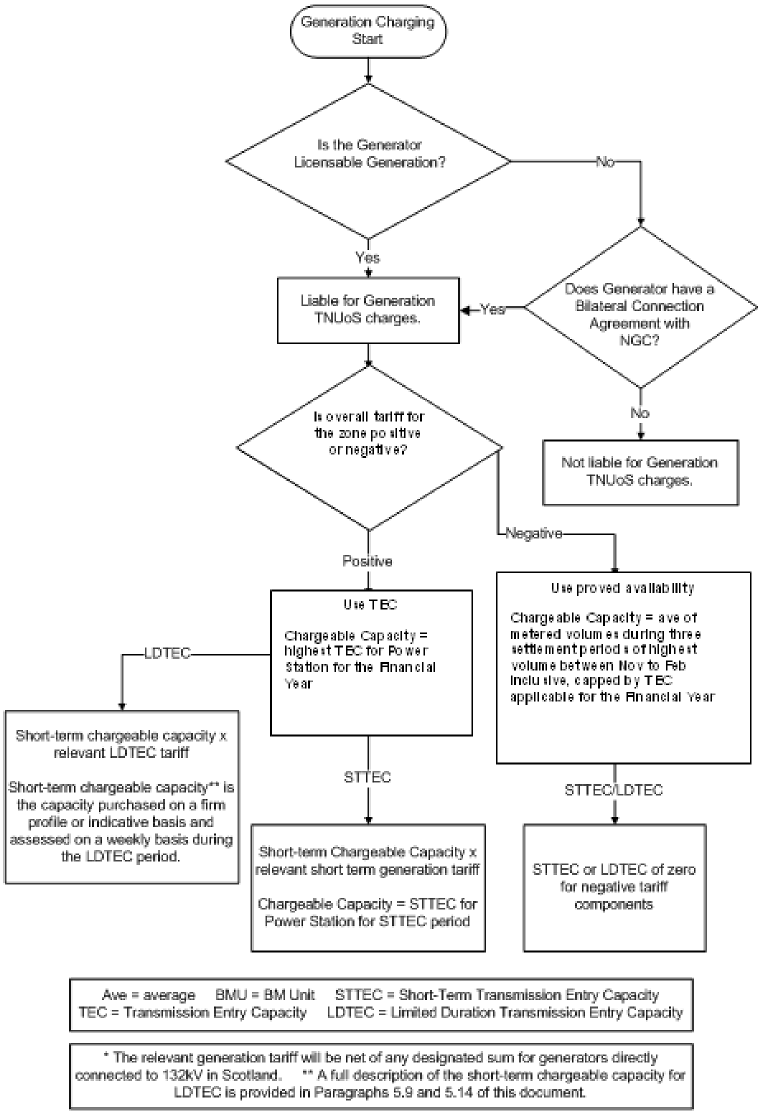



BMU = BM Unit  DDI = Derogated Distribution Interconnector
HH = Half hourly  NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

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# 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

## The Transport Model

### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

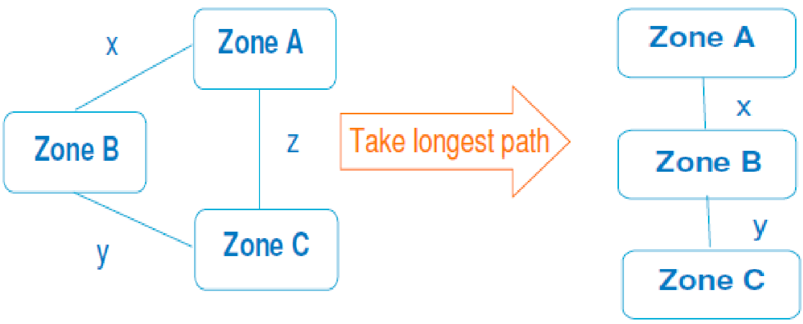
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

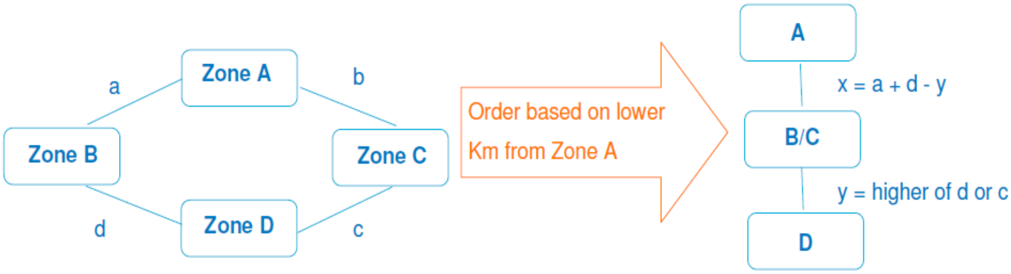
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

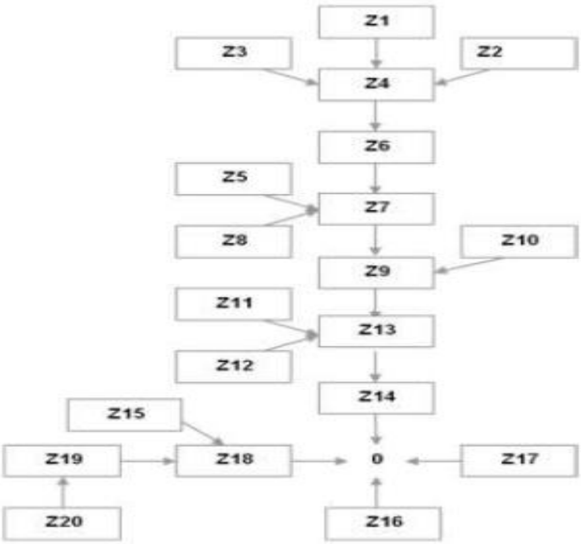
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company’s Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = For the first 5 charging years, starting with the charging year following the implementation date of CMP 264/265, £27.17 in April 2013 prices; indexed each year by the RPI formula set out in 14.3.6.
For the sixth charging year following the implementation date of CMP 264/265 and every subsequent charging year: Abs (RTG ) Only when Generation Residual is a negative value.
Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation has certification in accordance with Engineering Recommendation G59 (or a relevant replacement of G59 certification) before 01/11/2018.

G59 certification requirements are published by The Energy Networks Association.

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;

$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

Deleted: 113

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type

n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

Deleted: 114

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS} \times G_{Gi} \times ALF\right) = ITRR_{G\,YRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}(EETA_{Di} \times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14}(EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

| | | |
|---|---|---|
| $ELT_{Gi}$ | = | Effective Local Tariff (£/kW) |
| $SLT_{Gi}$ | = | Substation Local Tariff (£/kW) |

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$

Where

$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $LCRR_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the

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relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a

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number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

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$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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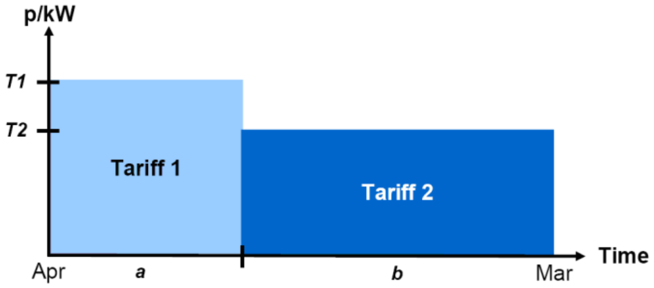
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

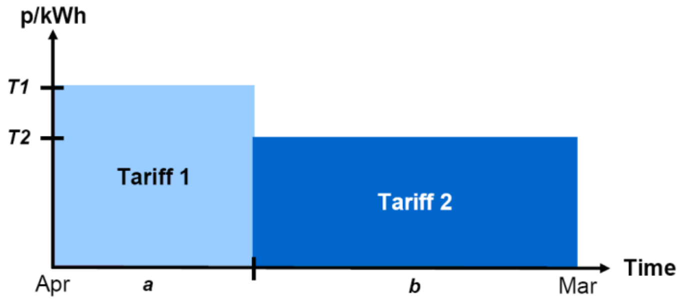
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{\frac{Chargeable\ Embedded}{Export\ Capacity}} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

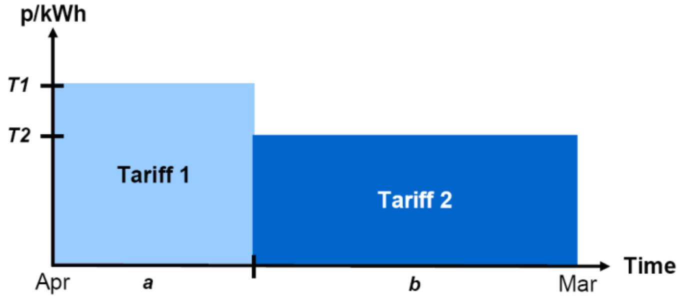
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

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**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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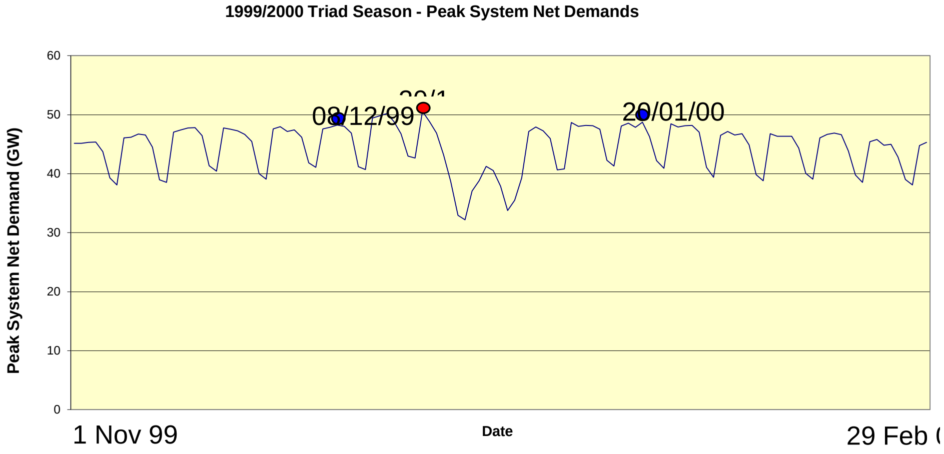


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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£779m - £140m - -£10m = £12.98/kW

50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17,000,000kWh - 18,000,000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1,000,000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16,700,000kWh – 17,000,000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| SUPPLIER | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| POWER STATION WITH A BILATERAL CONNECTION AGREEMENT | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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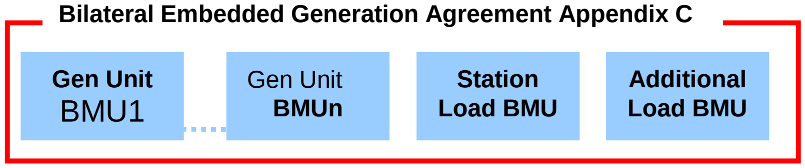
**PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.14, 14.17.15 and 14.17.18.** | See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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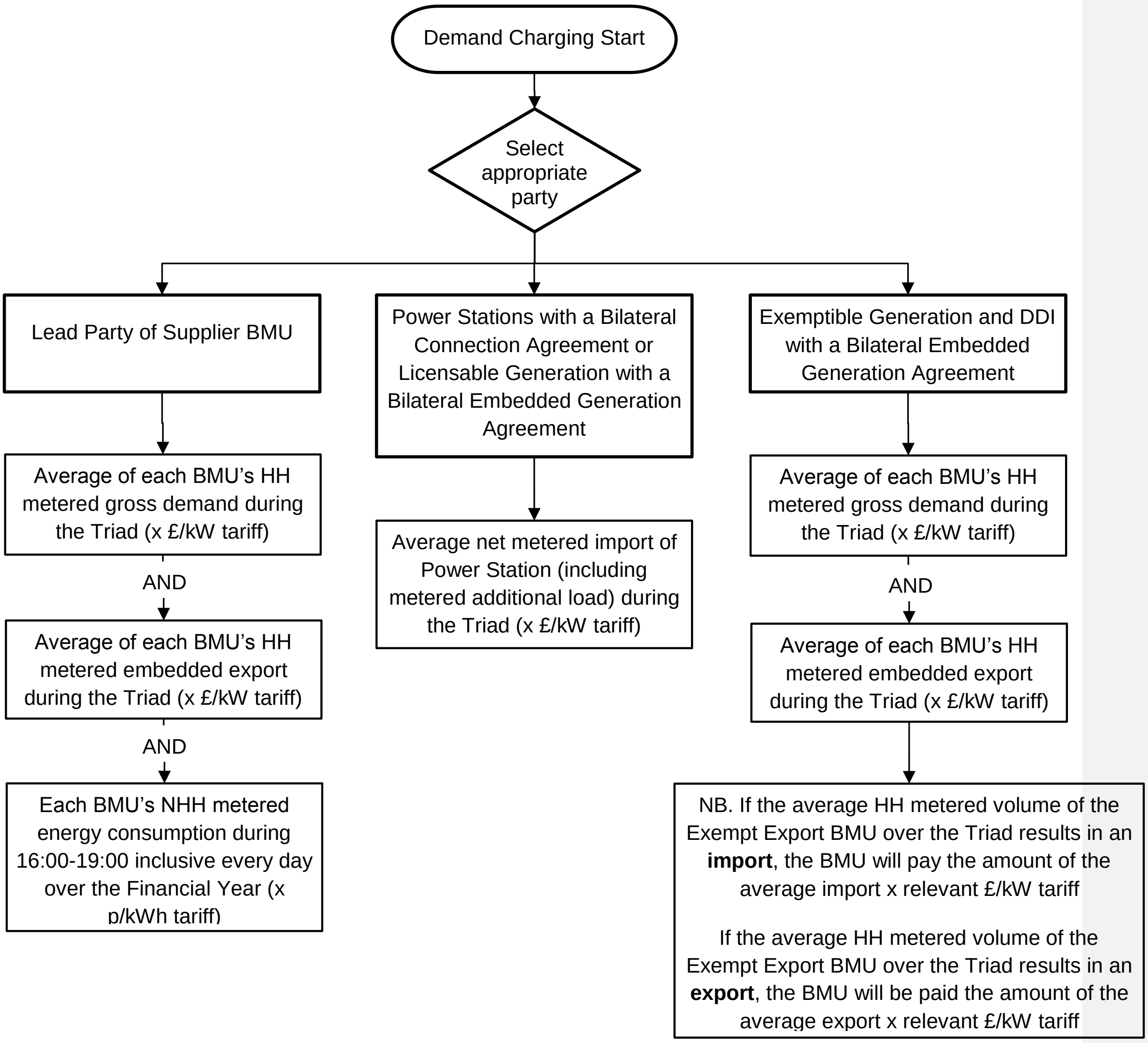
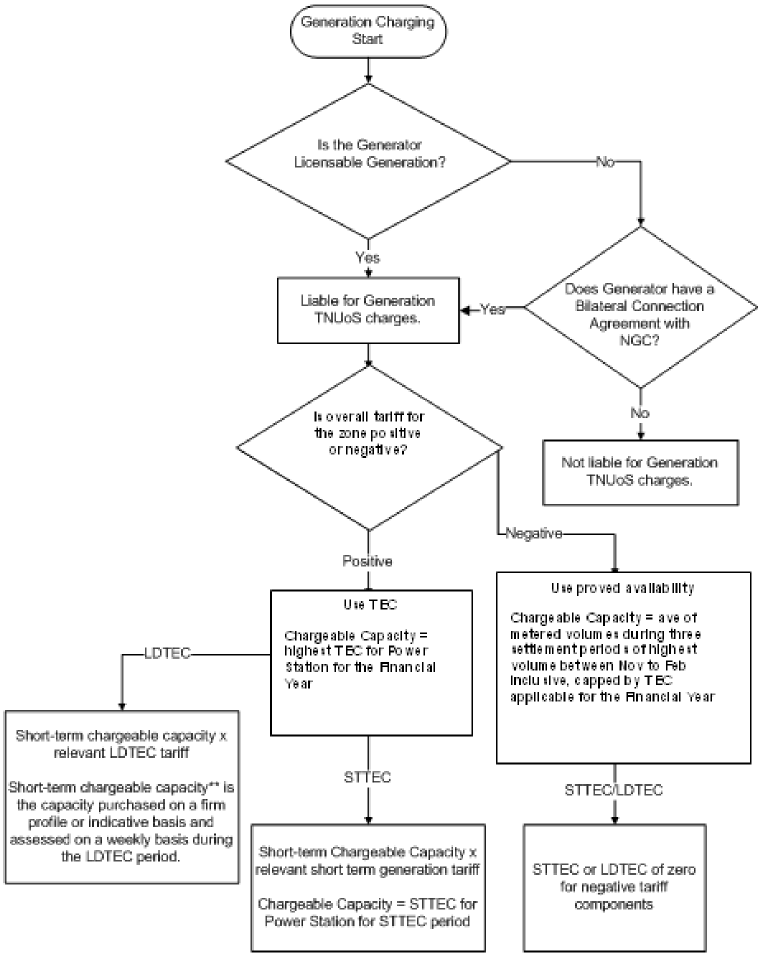



BMU = BM Unit    DDI = Derogated Distribution Interconnector
HH = Half hourly    NHH = Non-half hourly

Generation Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

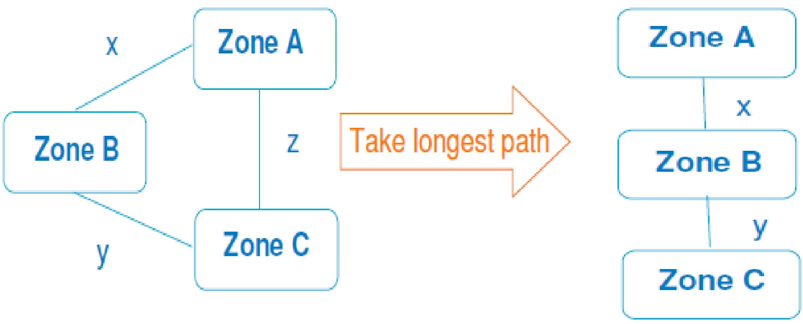
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

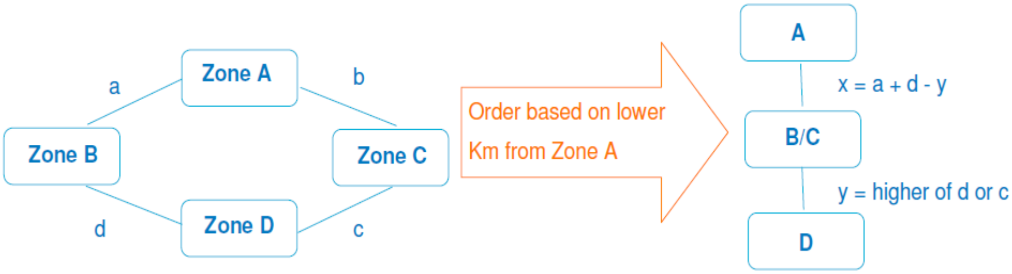
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

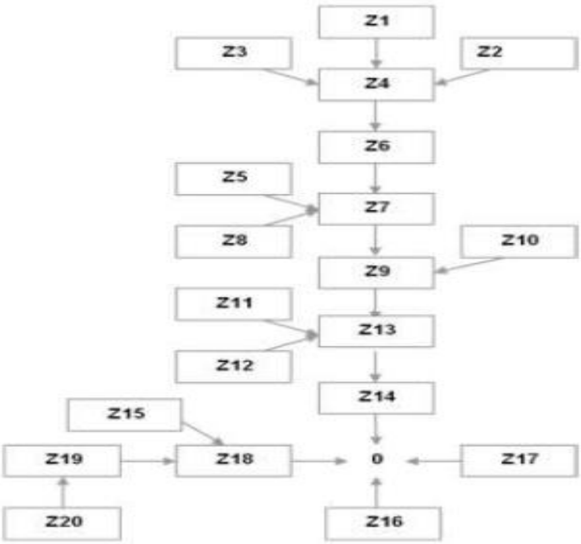
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ <u>then the BSF is calculated using the following formula: -</u>

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-\left(1+WACC\right)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$
$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$ = Peak Security Zonal Marginal km for each demand zone

$ZMkm_{DiYR}$ = Year Round Zonal Marginal km for each demand zone

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each demand one

$ITT_{DiYR}$ = Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$ITRR_D$ = Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts).

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = $ABs\ (Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation has certification in accordance with Engineering Recommendation G59 (or a relevant replacement of G59 certification) before 01/11/2018.

G59 certification requirements are published by The Energy Networks Association.

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS} \times G_{Gi} \times ALF\right) = ITRR_{G\,YRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by

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multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

ITRR$_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}(EETA_{Di} \times EEVA_{Di})$$

Where

ITTR$_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

EEVA$_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14}(EETG_{Di} \times EEVG_{Di})$$

Where

ITTR$_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

EEVG$_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

| | | |
|---|---|---|
| $ELT_{Gi}$ | = | Effective Local Tariff (£/kW) |
| $SLT_{Gi}$ | = | Substation Local Tariff (£/kW) |

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

$ELT_{Gi}$ = $LT_{Gi}$

Where

$LT_{Gi}$ = Final Local Tariff (£/kW)

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14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for

FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

$LCRR_G$ = Local Charge Revenue Recovery

$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore\\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to

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the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

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### Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEAi}$$
$$FT_{EEGi} = ET_{EEGi}$$

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14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating

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capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff} \quad \text{(£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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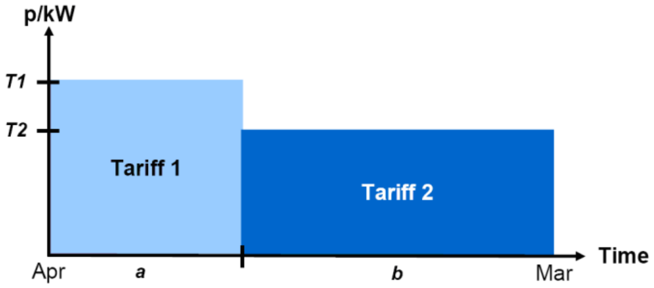
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

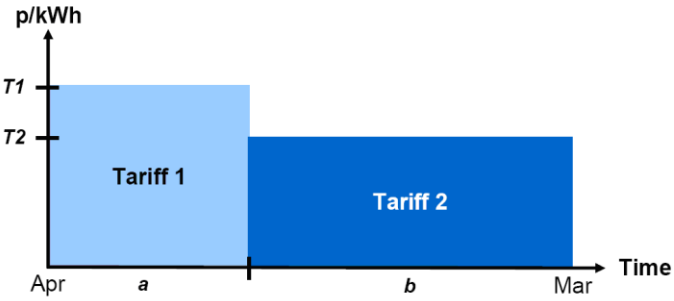
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

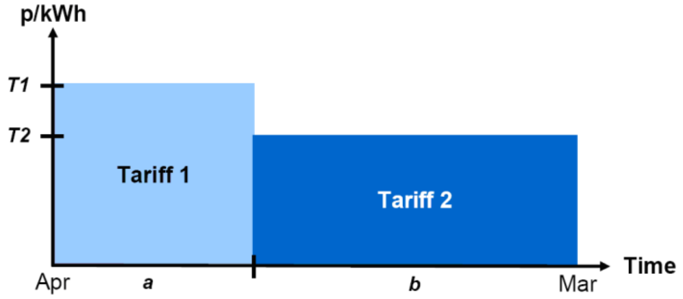
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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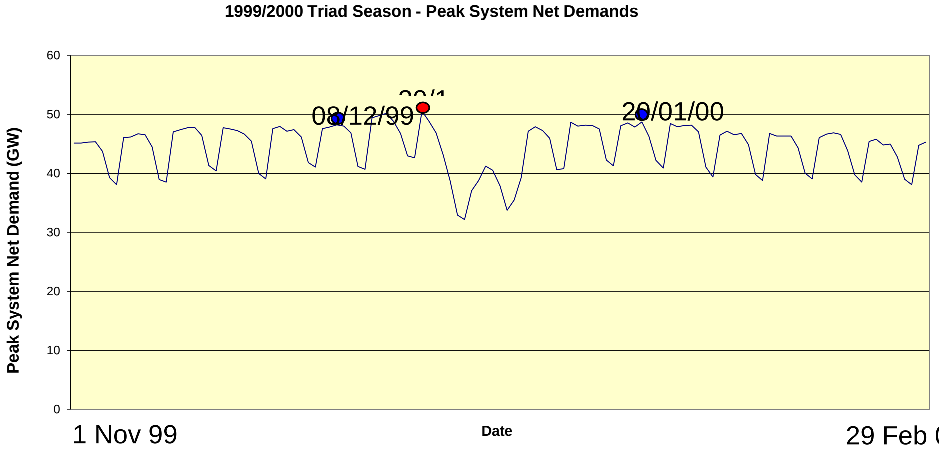


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50,000MW} = £12.98/kW$$

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¶
£779m - £140m - -£10m = £12.98/kW¶
50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

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As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17,000,000kWh - 18,000,000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1,000,000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16,700,000kWh – 17,000,000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April $1^{st}$ to March $31^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April $1^{st}$ to March $31^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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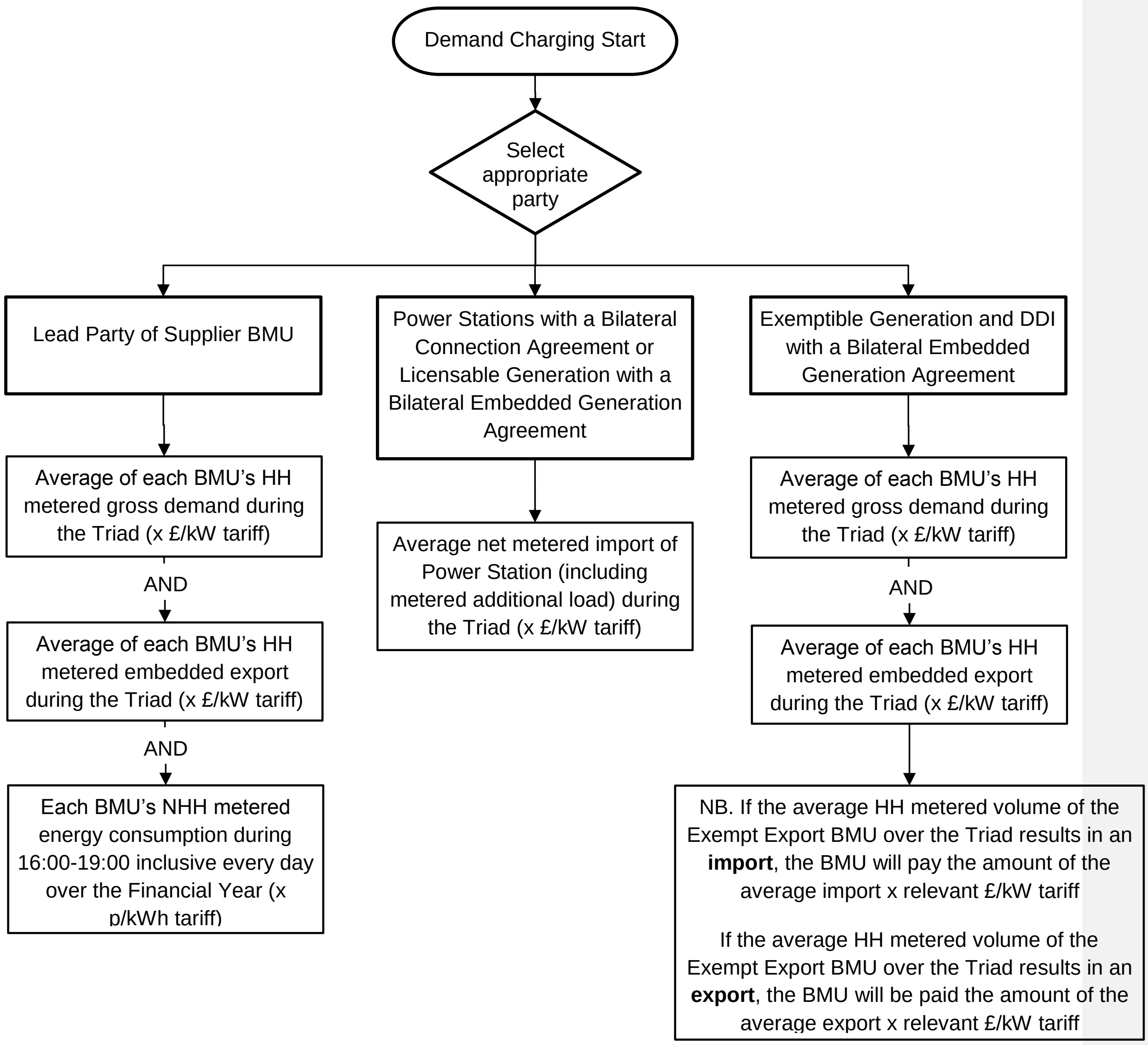
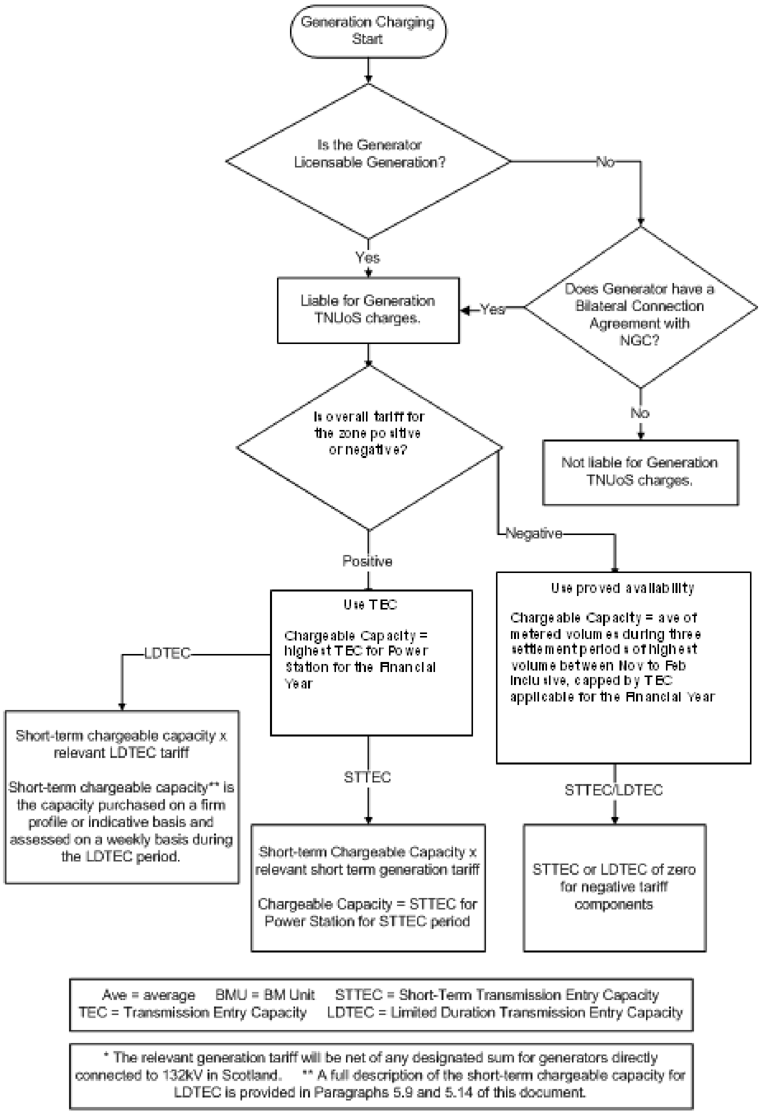



BMU = BM Unit　　DDI = Derogated Distribution Interconnector
HH = Half hourly　　NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
| --- | --- | --- |
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
| --- | --- | --- |
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

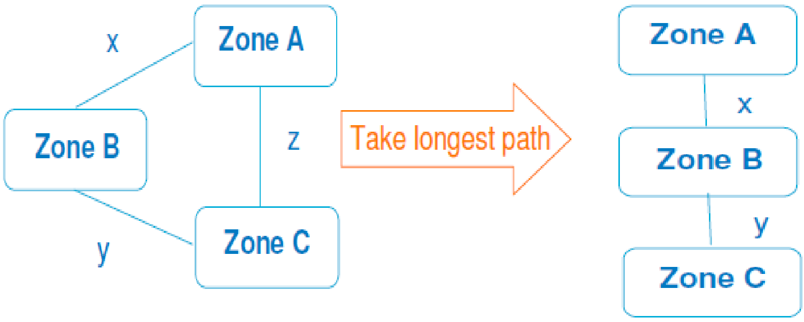
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

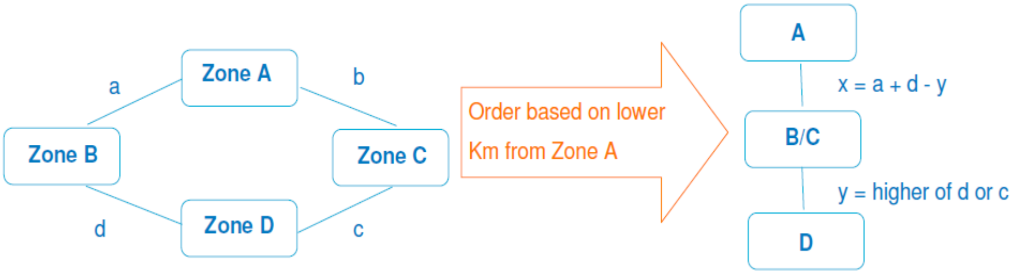
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

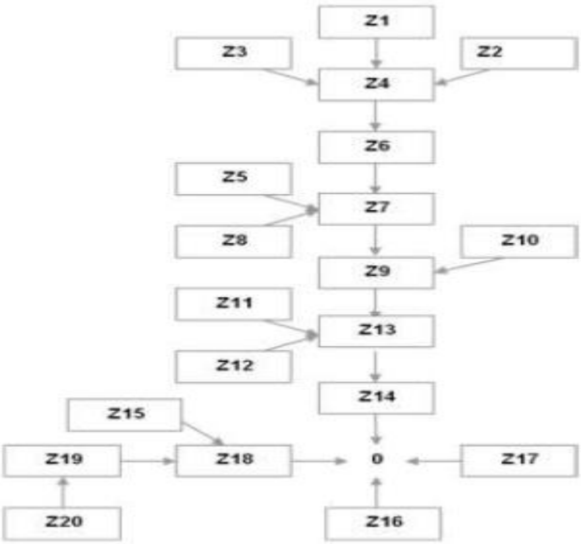
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = £0

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has certification in accordance with Engineering Recommendation G59 (or a relevant replacement of G59 certification) before 01/07/2019; or
- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 and which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
- In respect of a 'new build generating CMU'
- Having more than one delivery year
- And which has not been terminated

G59 certification requirements are published by The Energy Networks Association

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{GiYRNS} \times G_{Gi} \right) = ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS}\times G_{Gi}\times ALF\right)=ITRR_{G\,YRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}(EETA_{Di}\times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG}=\sum_{Di=1}^{14}(EETG_{Di}\times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

Deleted: 116

$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

Deleted: 117

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |

| | | | | |
|---|---|---|---|---|
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore

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Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

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14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

### Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

### Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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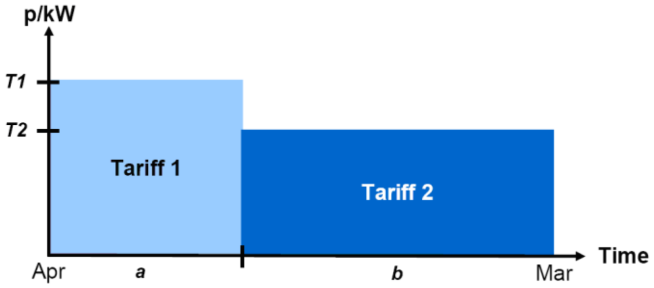
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

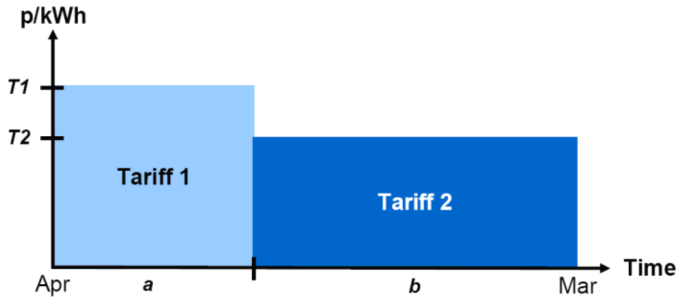
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Embedded\ Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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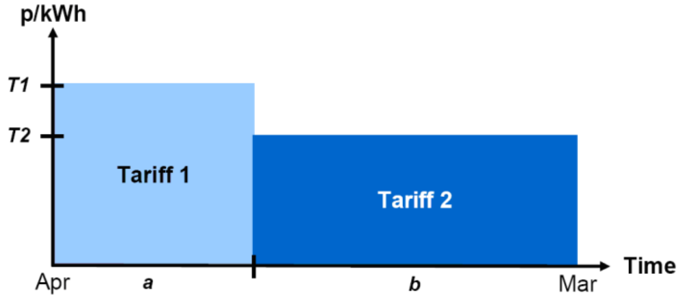
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.
- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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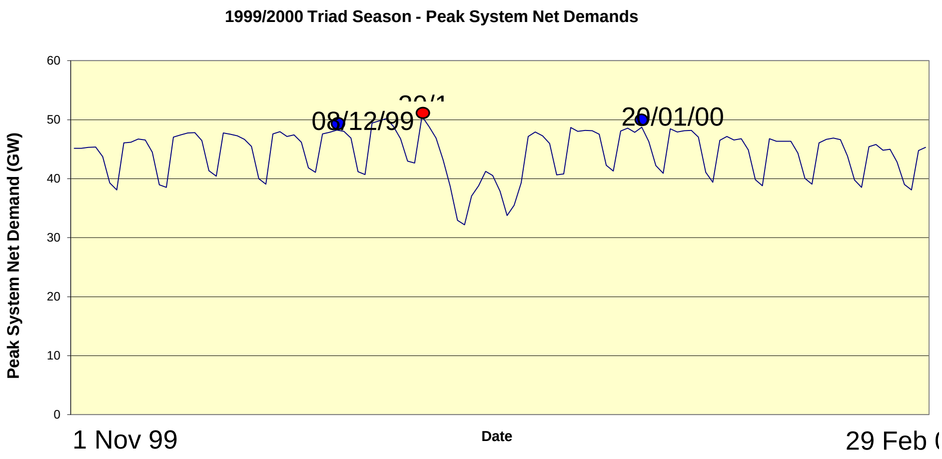


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50,000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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£779m - £140m - -£10m = £12.98/kW

50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

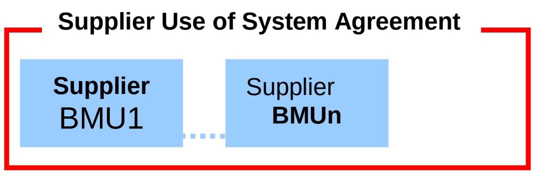
**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

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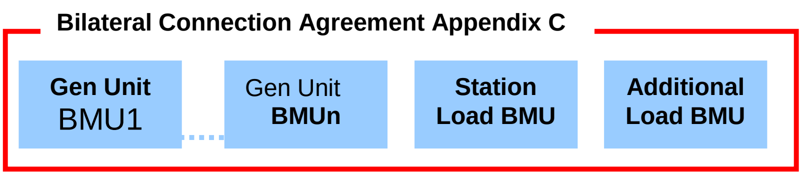
**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.14.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><th colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</th></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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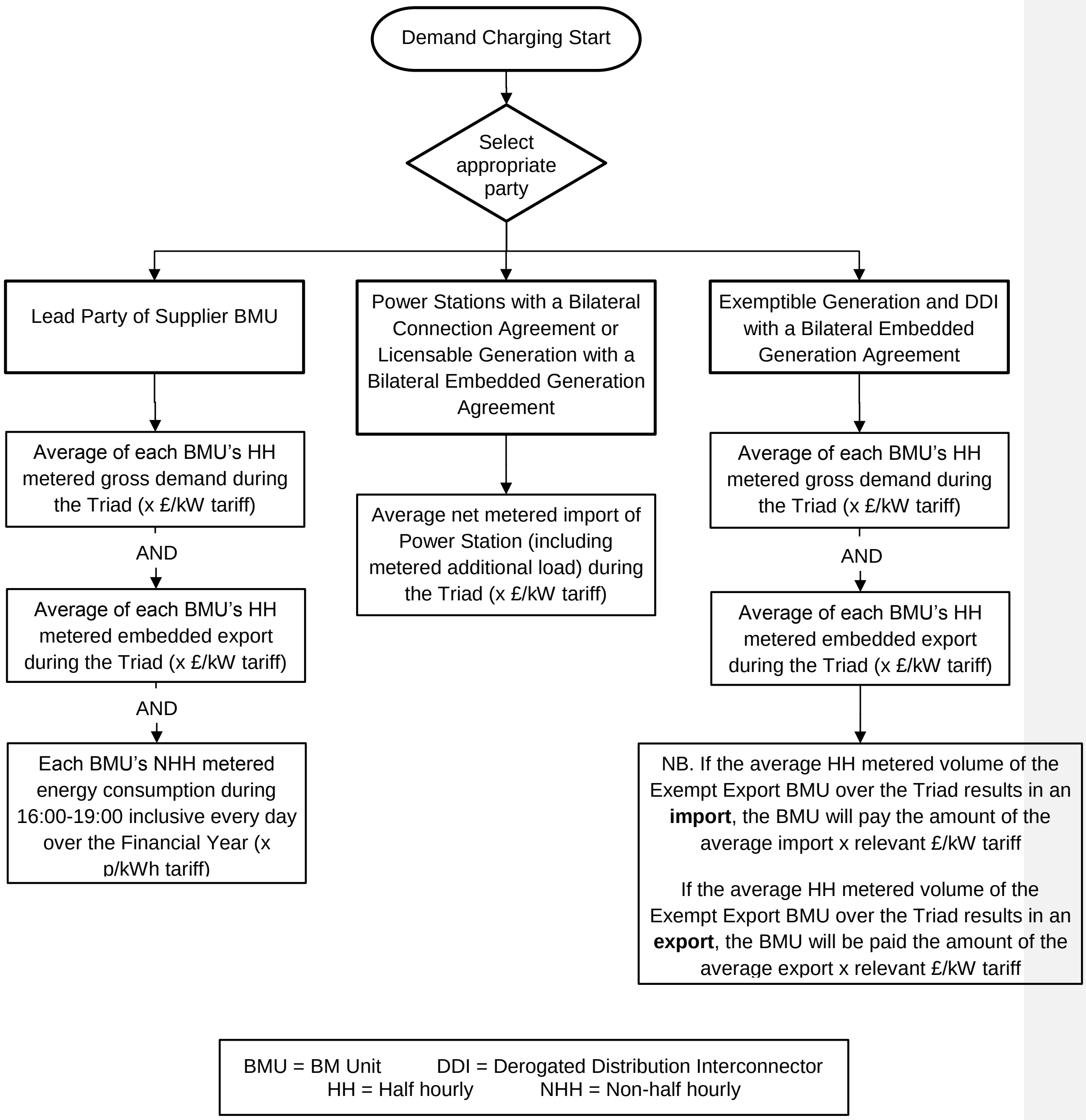
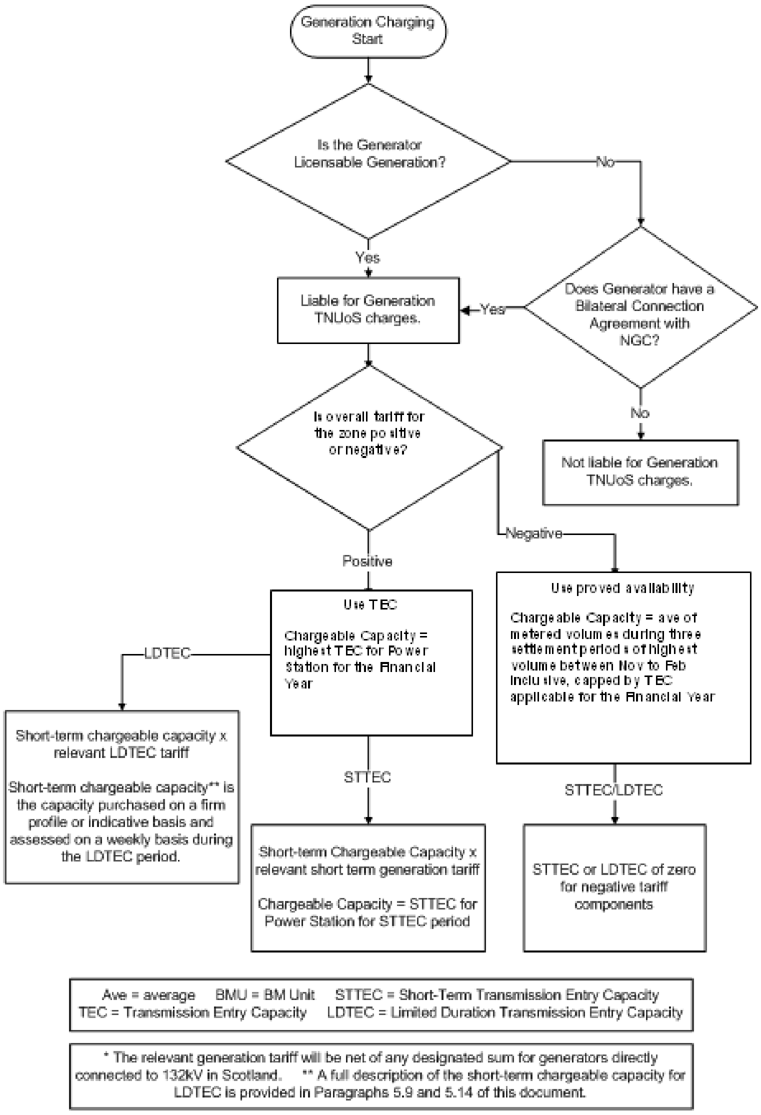


Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

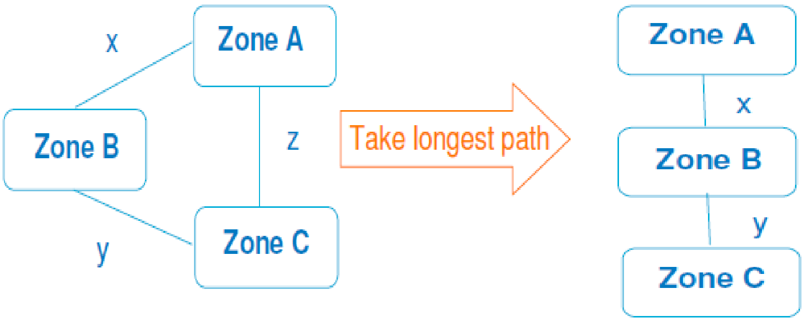
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

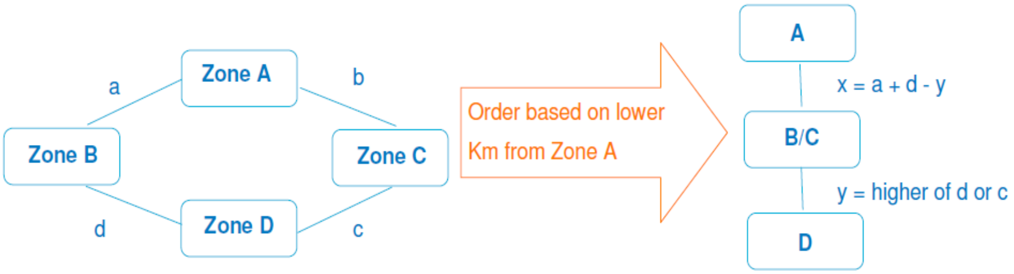
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

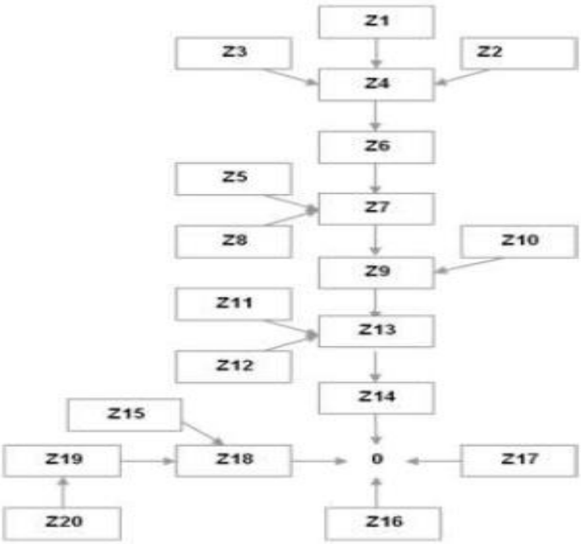
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

## Offshore Interlinks

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$
$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$ = Peak Security Zonal Marginal km for each demand zone

$ZMkm_{DiYR}$ = Year Round Zonal Marginal km for each demand zone

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each demand one

$ITT_{DiYR}$ = Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$ITRR_D$ = Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts).

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
| --- | --- |
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = For the first charging year following implementation, £34.11 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.
In every subsequent charging year, AGIC + (£18.50 in April 2019 prices; indexed each year by the RPI formula set out in 14.3.6).

Where
AGIC= The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 For the first 10 charging years following implementation, Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has certification in accordance with Engineering Recommendation G59 (or a relevant replacement of G59 certification) before 01/07/2017; or
- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
- In respect of a 'new build generating CMU'
- Having more than one delivery year
- And which has not been terminated

G59 certification requirements are published by The Energy Networks Association

In every subsequent charging year, all Grandfathered Embedded Exports will be considered Affected Embedded Exports.

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £34.11 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS}\times D_{Di}\right)=ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14} (EETA_{Di} \times EEVA_{Di})$$

Where

ITTR$_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

EEVA$_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

ITTR$_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

EEVG$_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_{k}$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

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14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$LCRR_G = \sum_{j=Gi} LT_{Gi} * G_j$$

Where

| | | |
|---|---|---|
| $LCRR_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where
$TRR_t$ = TNUoS Revenue Recovery target for year t
$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.
$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t
$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

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14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where
RT = Residual Tariff (£/MW)
p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$ and $$FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}}$$ and $$FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

## Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff} \quad (\text{£/kW/period})$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Deleted: $Annual\ Liability_{D}$

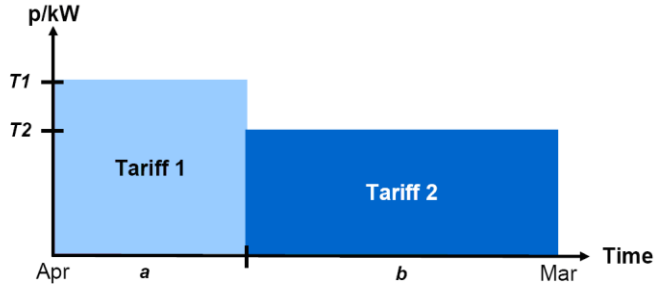
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

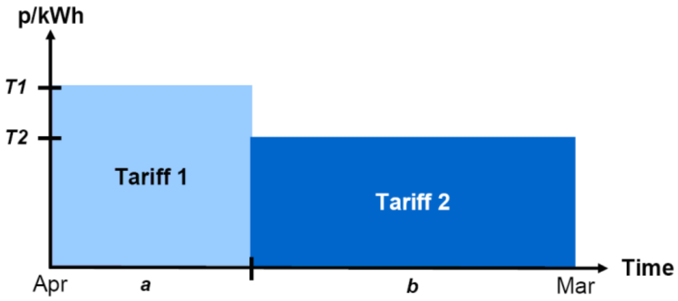
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

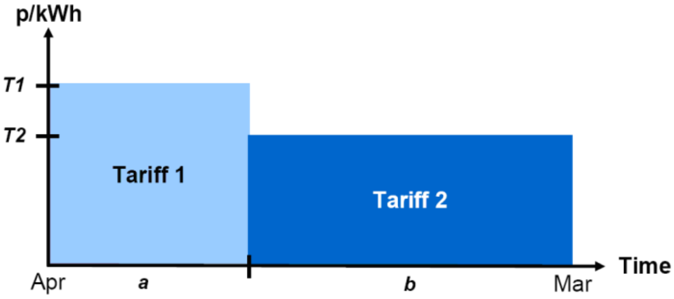
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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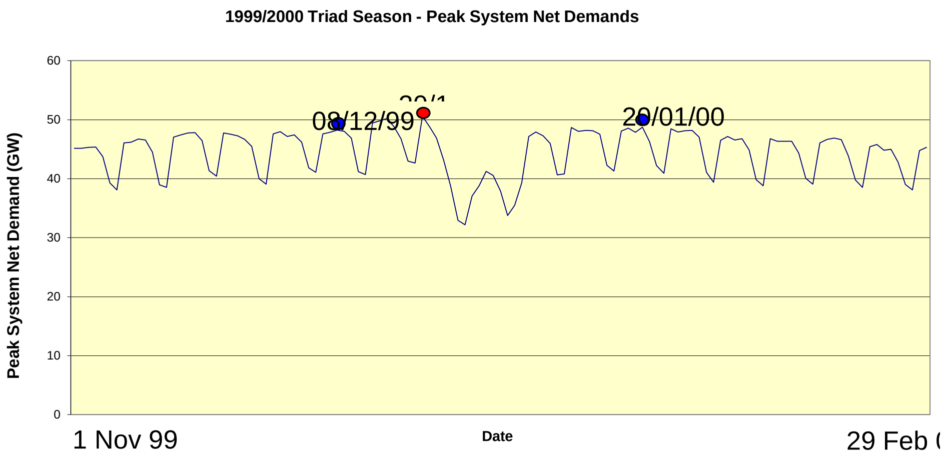


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

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14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:
- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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£779m - £140m - -£10m = £12.98/kW
50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

$= (9{,}000kW - 7{,}200kW) \times$ £10.00/kW

$= 1{,}800kW \times$ £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

$= (-500kW - -600kW) \times$ £5.00/kW

$= 100kW \times$ £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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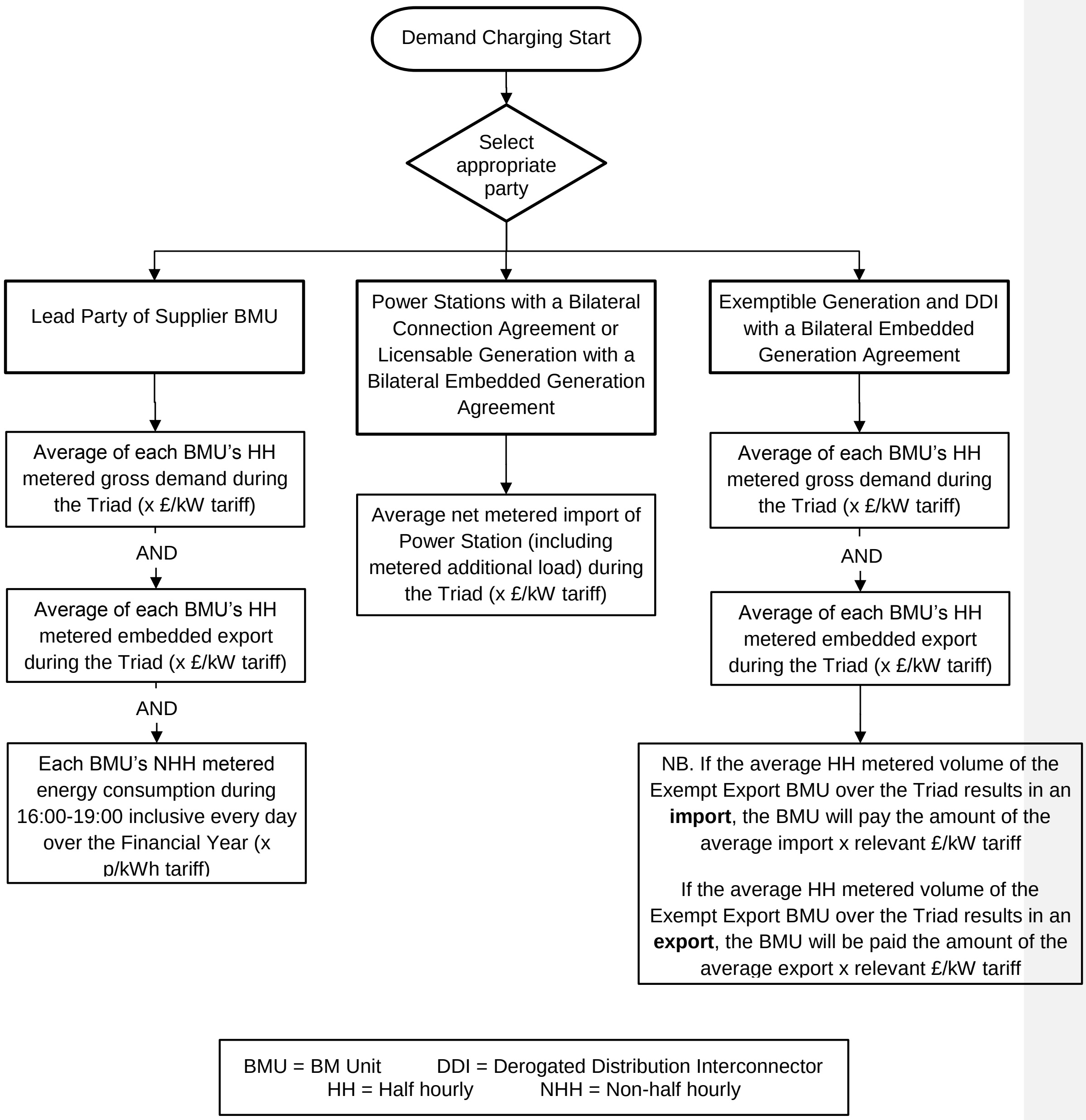

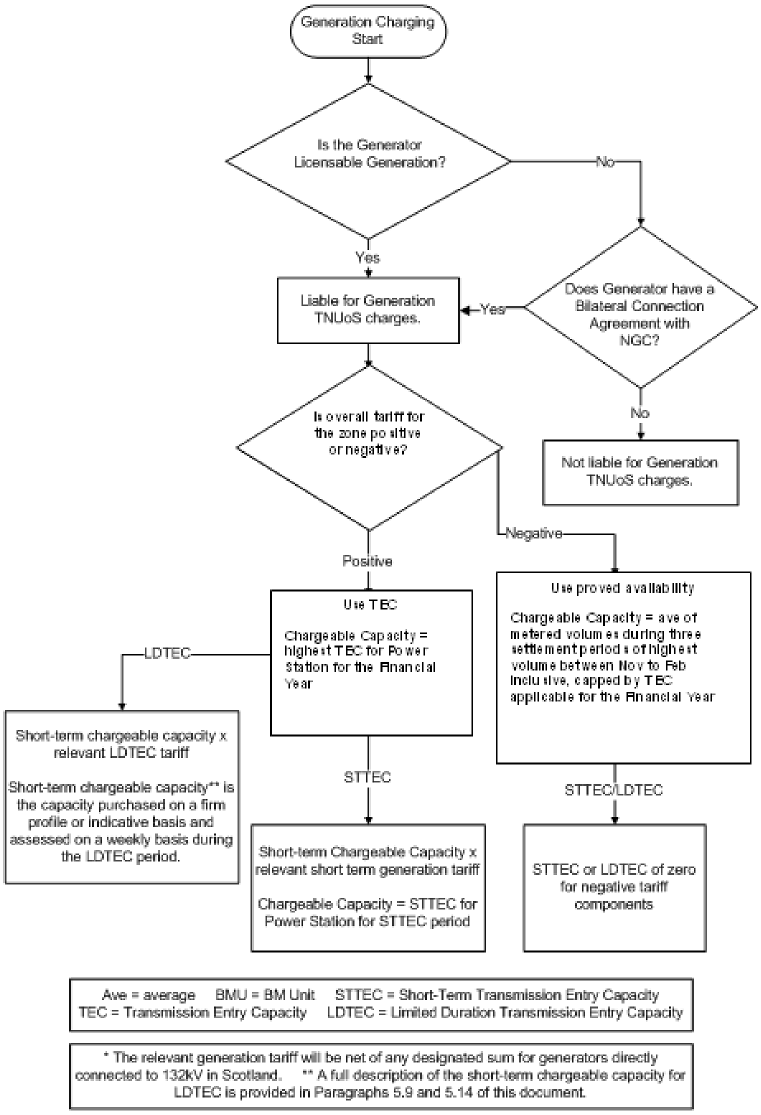
Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Liable for Generation TNUoS charges.
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

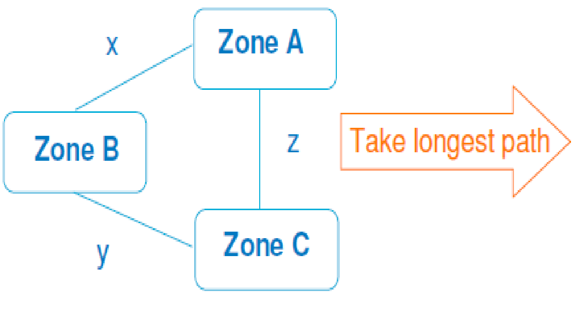
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

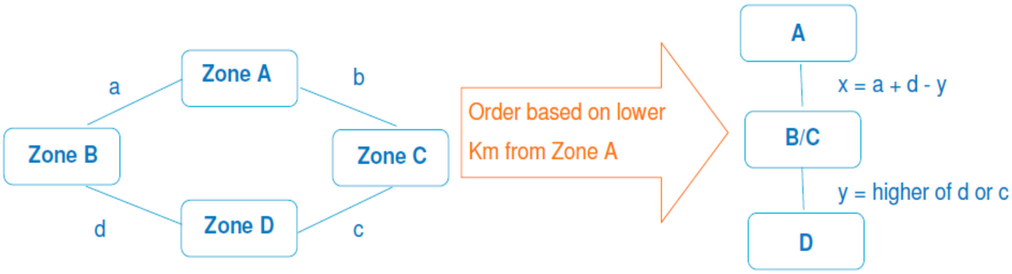
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

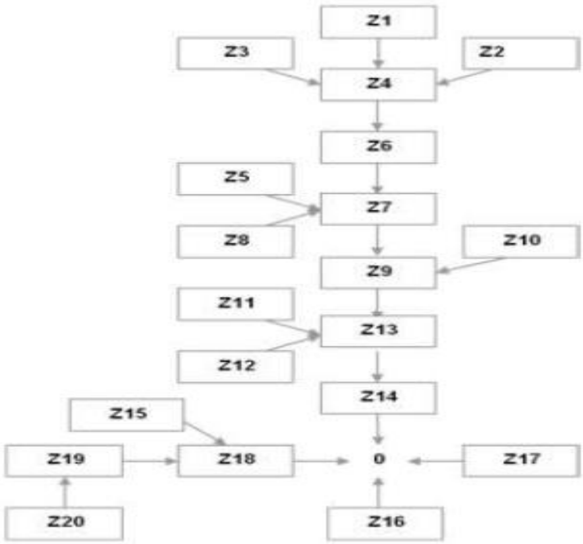
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year “t” the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS and where all associated generation holds a non-terminated Capacity Market obligation at any point during the charging year.

- The ownership of a Capacity Market obligation can be from auction or from a trade.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = £0

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where
$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

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14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

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14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

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14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

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14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_G = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

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**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of

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time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

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$$RT_D = \frac{(p \times TRR) - I}{}$$

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum,

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determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

## Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

## Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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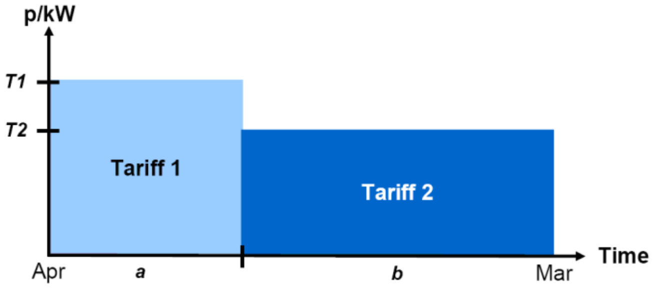
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

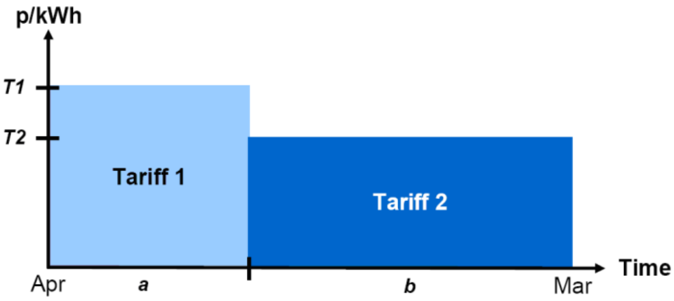
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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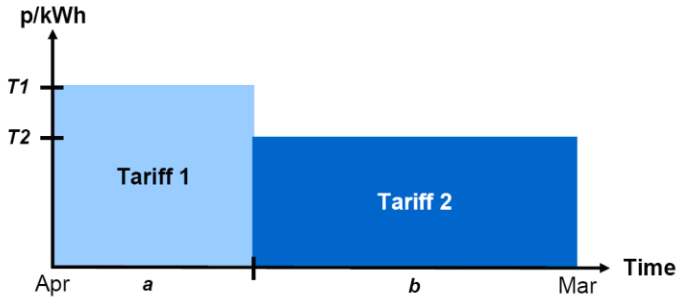
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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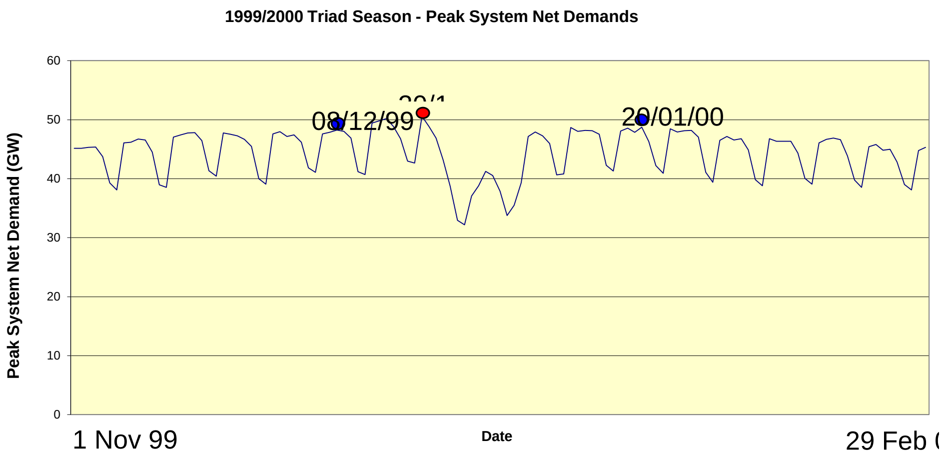


### Half-hourly metered demand charges

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

### Monthly Charges

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

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b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= (17,000,000kWh - 18,000,000kWh) x 1.20p/kWh

100

= -1,000,000kWh x 1.20p/kWh
100

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = (16,700,000kWh – 17,000,000kWh) x 1.20p/kWh
100
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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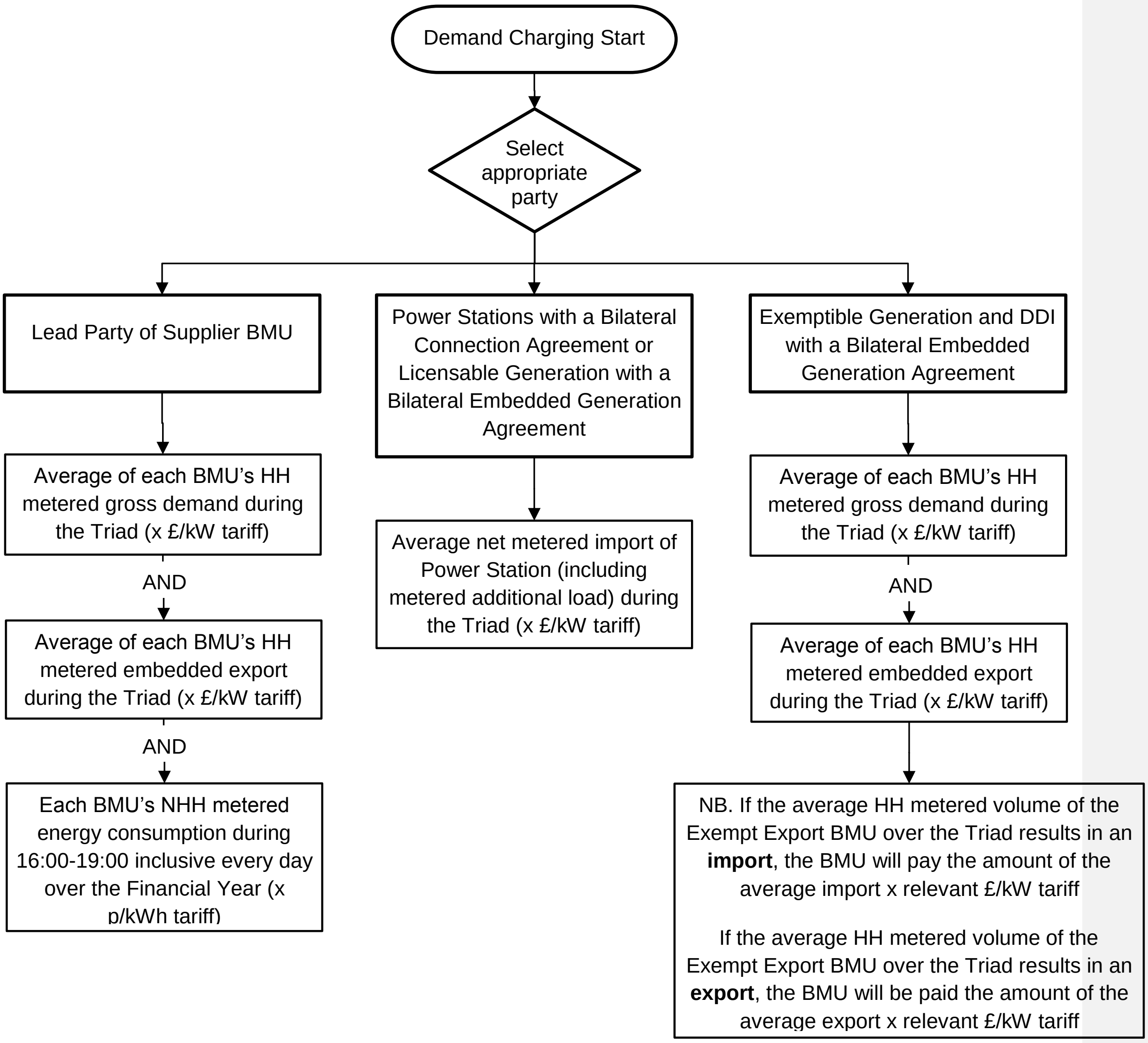
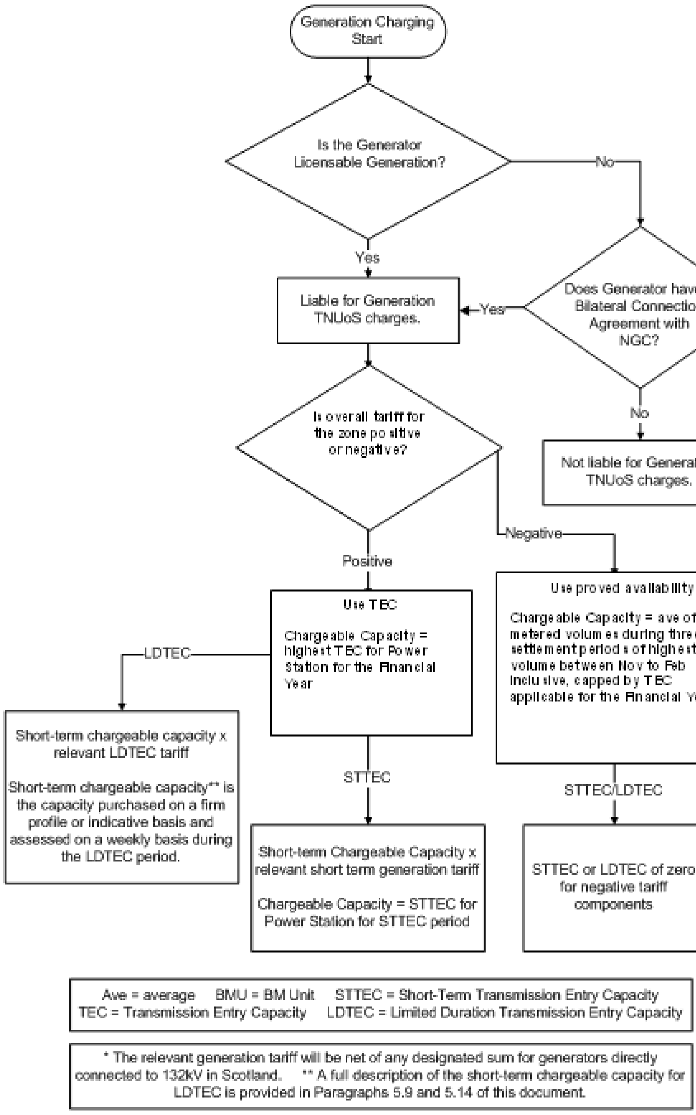



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year



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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM1

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

## Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

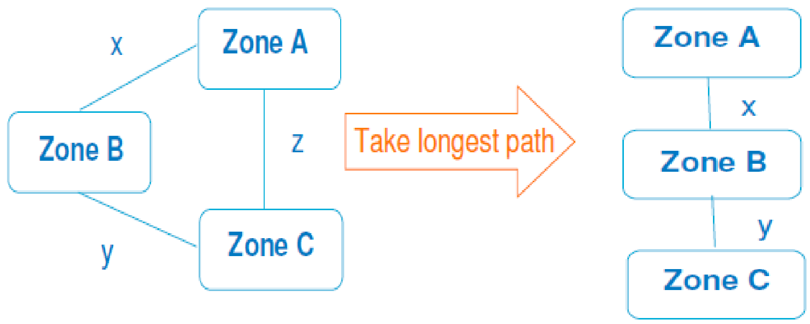
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

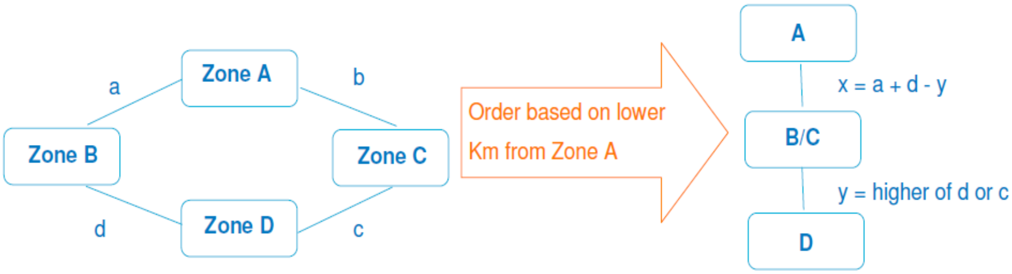
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

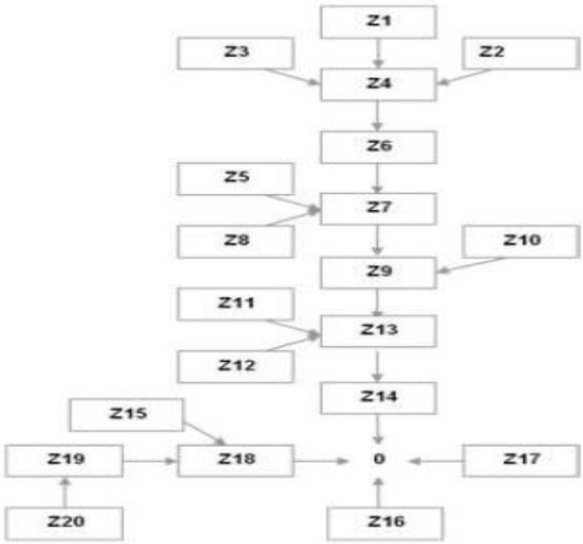
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ <u>then the BSF is calculated using the following formula: -</u>

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{\mathrm{k}} \mathrm{Gen_k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = $RT_G \times -1$

Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}\left(EET_{Di} \times EEV_{Di}\right)$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the

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relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a

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number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

### Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$ and $$FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $$RFT_{Di} = FT_{Di} + NRRT_D$$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} *100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Deleted: $Annual\ Liability_{D}$

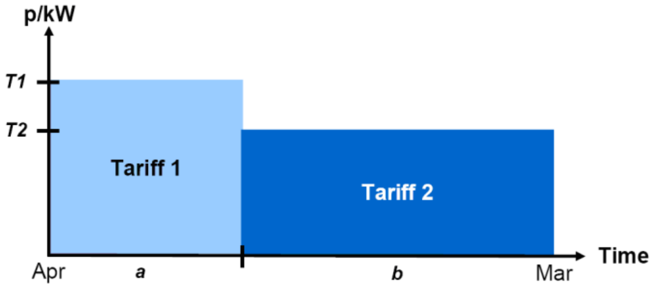
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$\begin{aligned} Annual\ Liability_{Energy} &= Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity \\ &+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity \end{aligned}$$

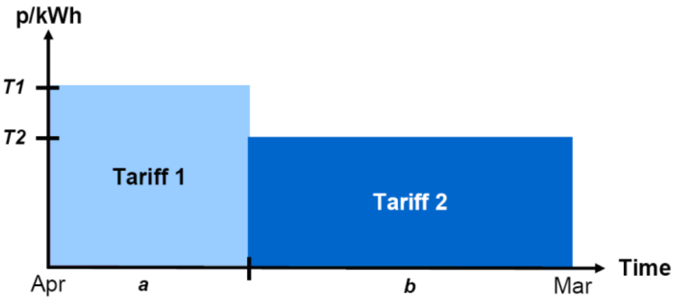
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Deleted: $Annual\ Liability_{D}$

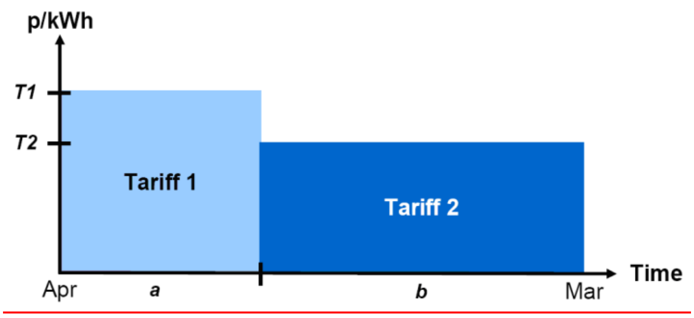
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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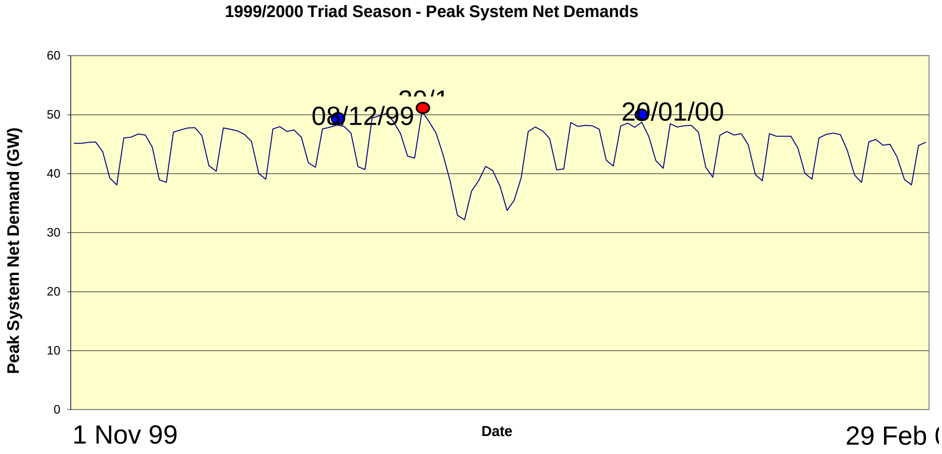


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50,000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW = £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW = -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$ = -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHD_F}$ = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHEE_A}$ = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{HHEE_F}$ = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{NHHC_A}$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

$\mathbf{NHHC_F}$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** / **Station Load BMU** / **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><td colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</td></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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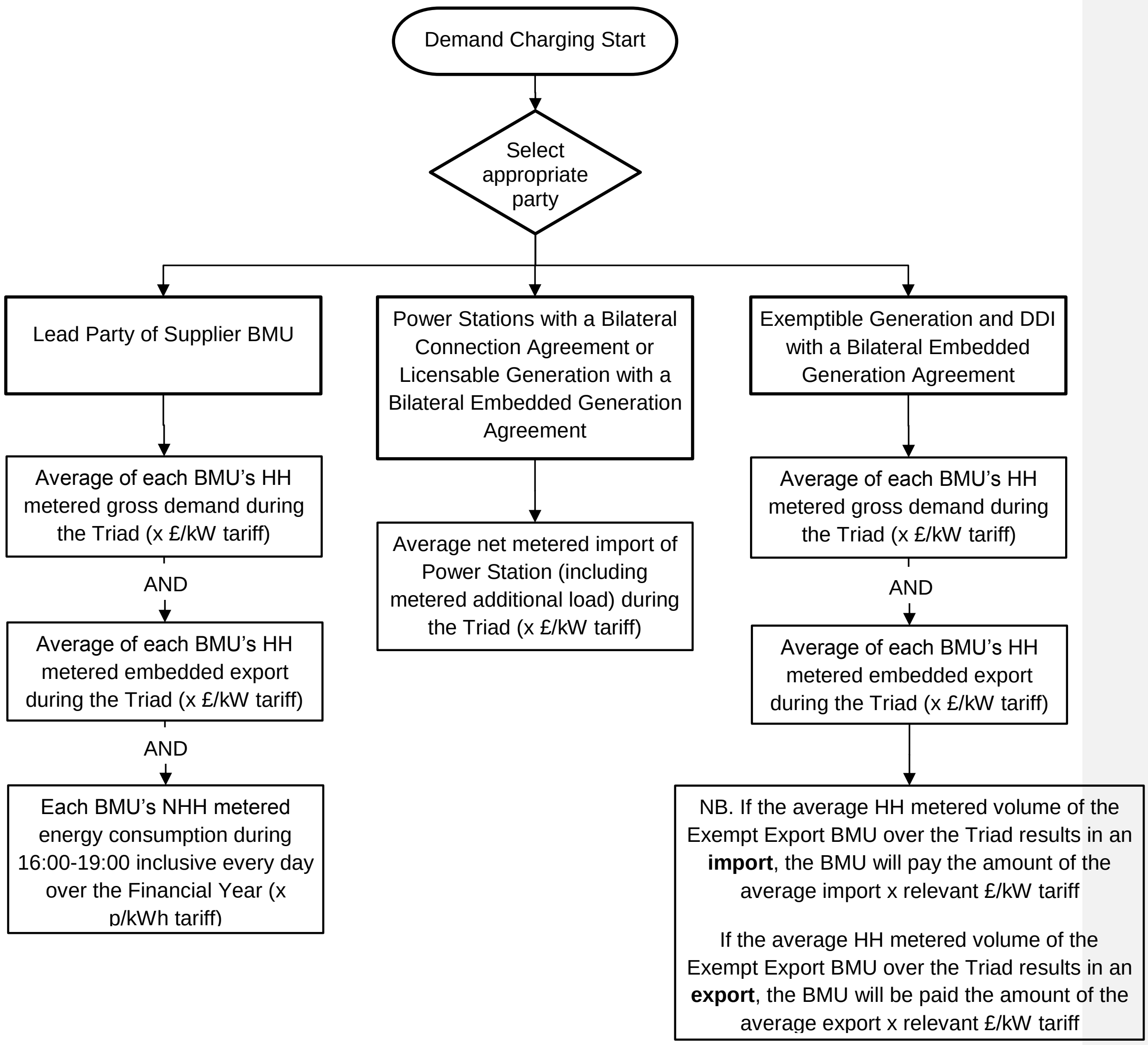
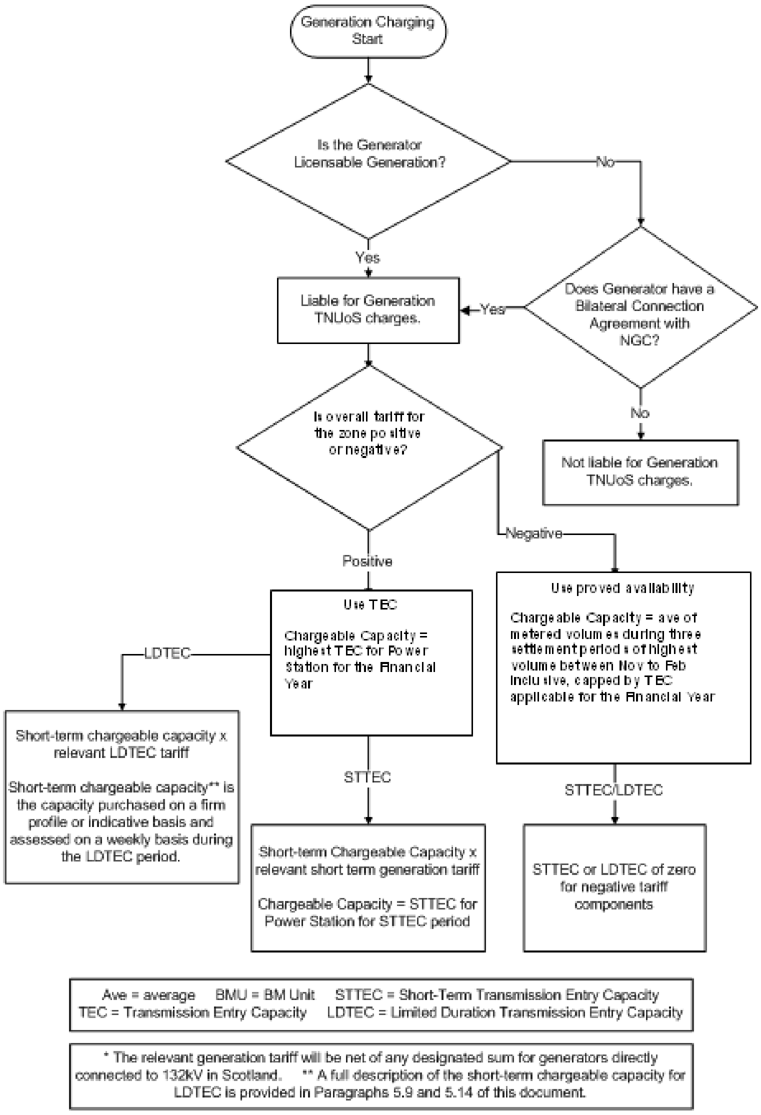



BMU = BM Unit　　DDI = Derogated Distribution Interconnector
HH = Half hourly　　NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM2

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where
$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model
$WNMkm_{YR}$ = Year Round Weighted nodal marginal km
$ZMkm_{YR}$ = Year Round Zonal Marginal km
Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:
Di = Demand zone
Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

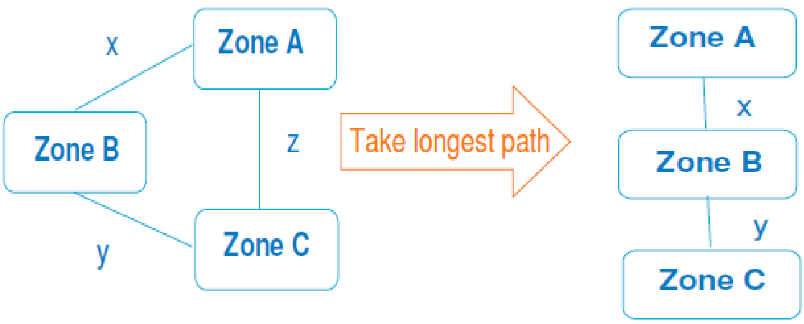
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

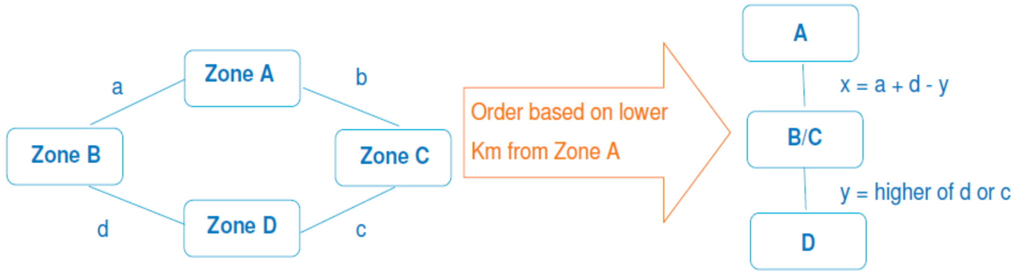
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

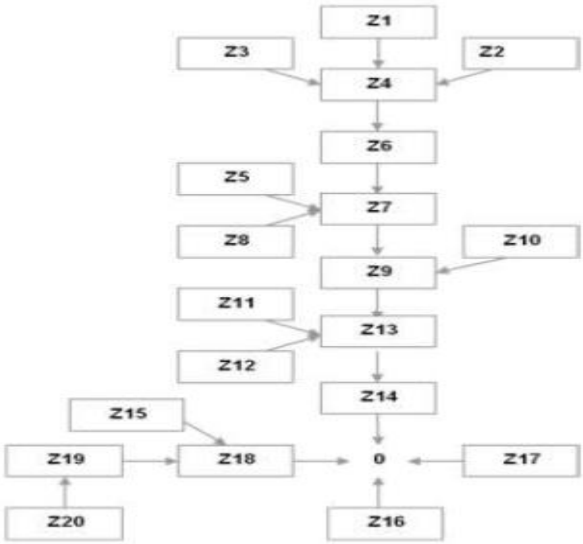
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\dfrac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_k} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

## TNUoS Embedded Export Tariff

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$EX = \frac{2}{3}(XP - (RT_G \times -1)) + (RT_G \times -1)$$

Second charging year following the implementation date of CMP 264/265:

$$EX = \frac{2}{3}(XP - (RT_G \times -1)) + (RT_G \times -1)$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$EX = (RT_G \times -1)$$

Where
XP = Value of demand residual in charging year prior to implementation
$(RT_G \times -1)$ = Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiPS} \times D_{Di}) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

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$$ITRR_{EE} = \sum_{Di=1}^{14} (EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ (MW) = Forecast Embedded Export metered volume at Triad

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

| | | |
|---|---|---|
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}}$$ and $$FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $$RFT_{Di} = 0$$

For *i*=z+1 to 14: $$RFT_{Di} = FT_{Di} + NRRT_D$$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} *100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

### Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

### Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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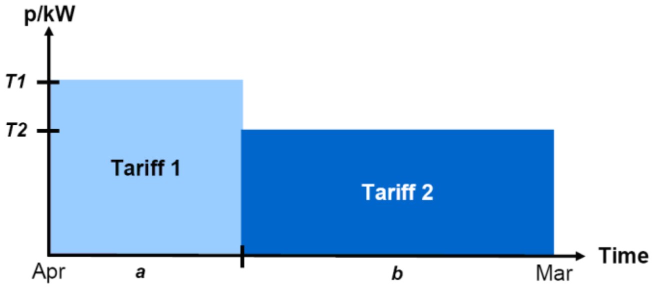
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

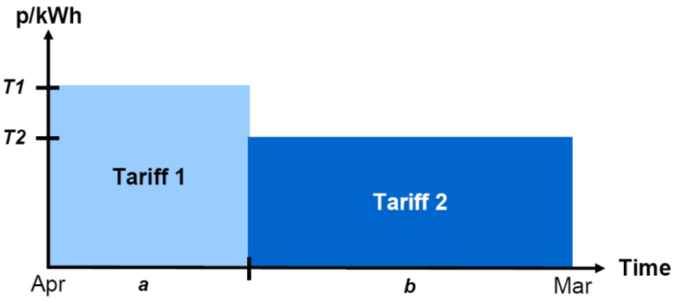
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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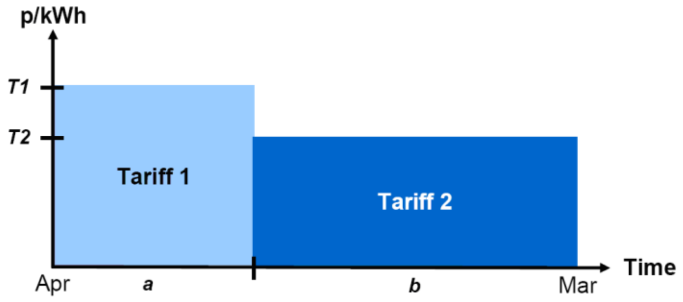
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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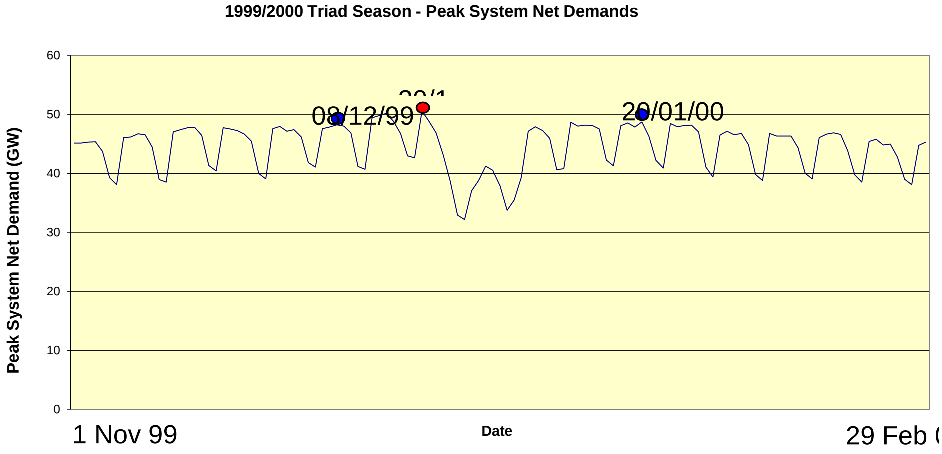


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| SUPPLIER | |
|---|---|
| Supplier Use of System Agreement<br>Supplier BMU1 ..... Supplier BMUn | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| POWER STATION WITH A BILATERAL CONNECTION AGREEMENT | |
|---|---|
| Bilateral Connection Agreement Appendix C<br>Gen Unit BMU1 ..... Gen Unit BMUn · Station Load BMU · Additional Load BMU | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><td colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</td></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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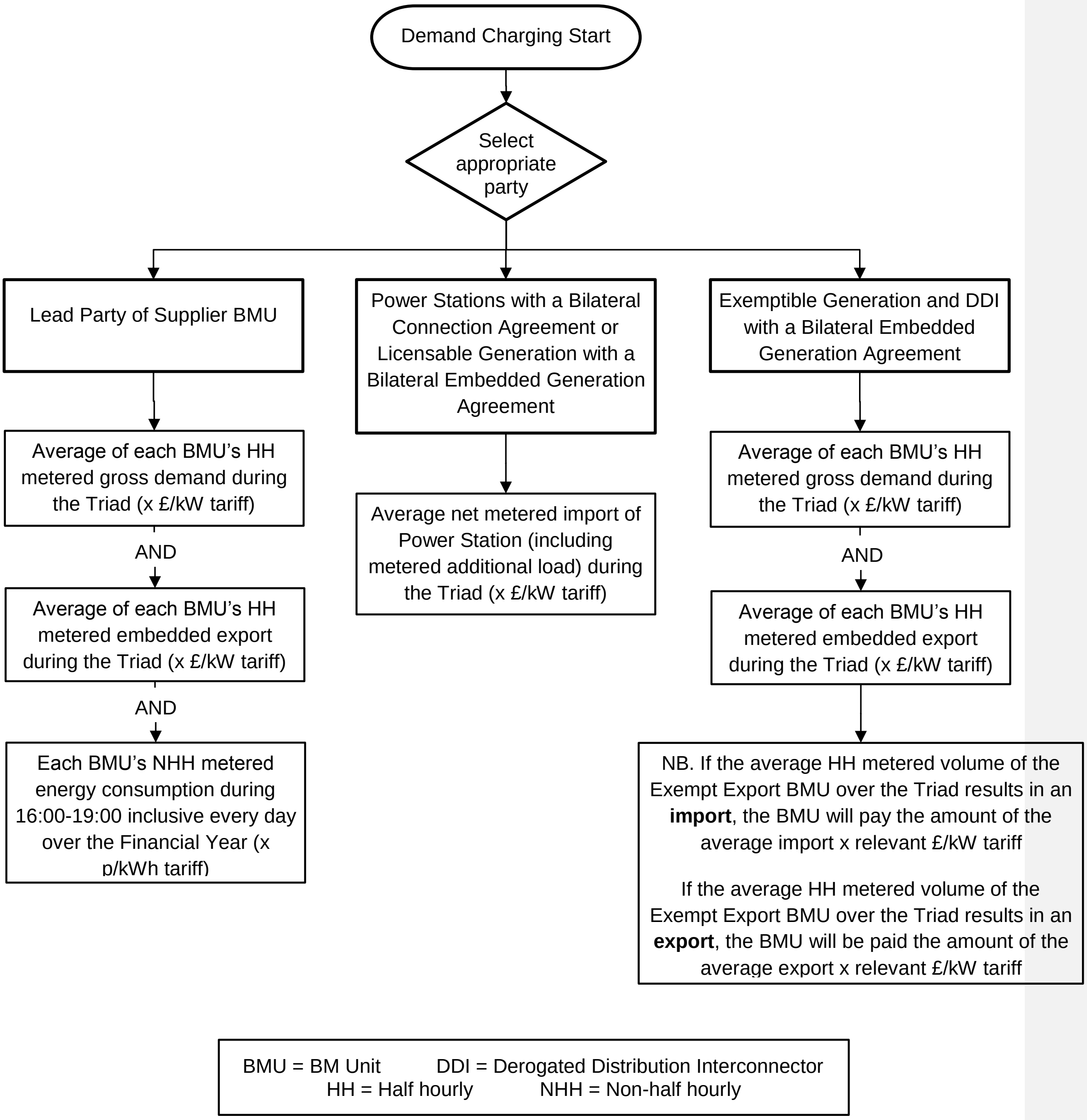

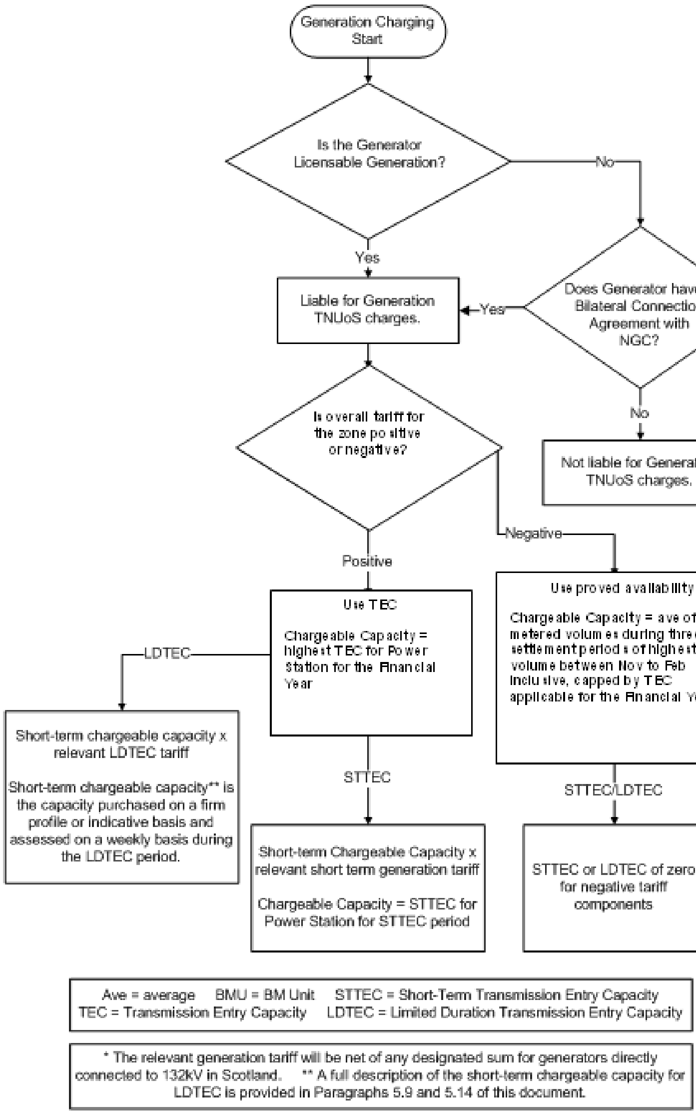
Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM3

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

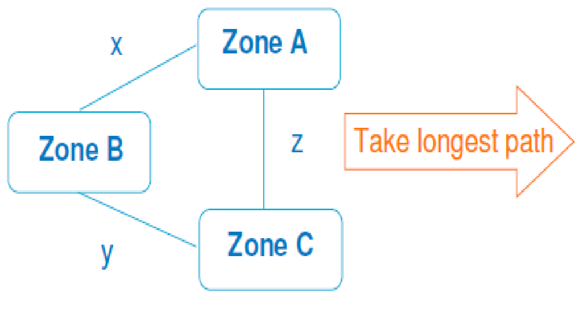
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

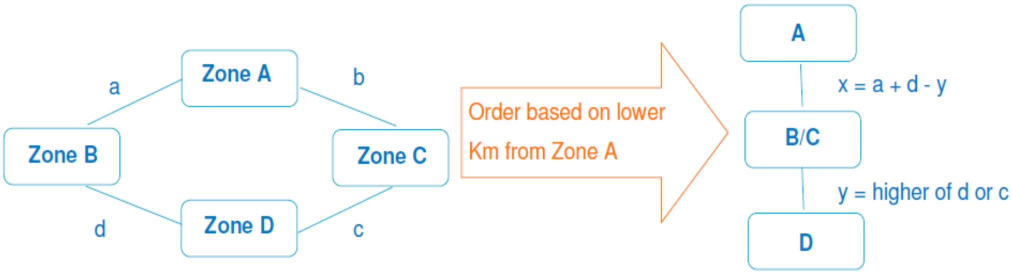
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

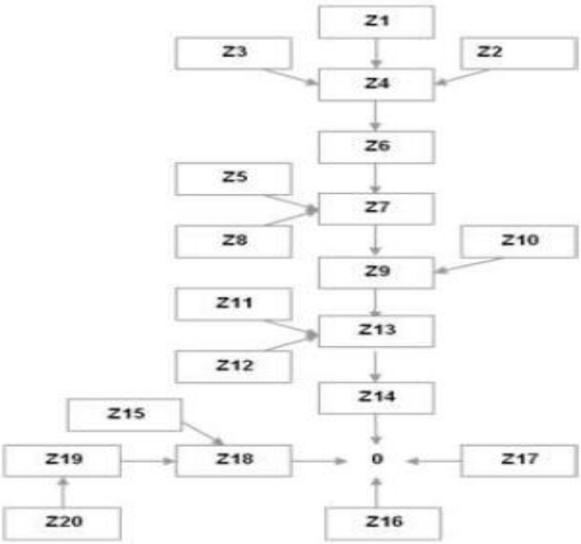
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\dfrac{\left(1-\left(1+WACC\right)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| **400kV OHL expansion constant calculation** | **Ave £/MWkm** |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

Deleted: 113

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiPS} \times D_{Di}) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

Deleted: 114

$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

Deleted: 115

$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ (MW) = Forecast Embedded Export metered volume at Triad

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

Deleted: 116

$$\sum_k \frac{NLMkm_{Gj}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore\\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

$SLT_k$ = the offshore substation tariff for substation k

$Gen_k$ = the generation connected to offshore substation k

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_{D}$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag

- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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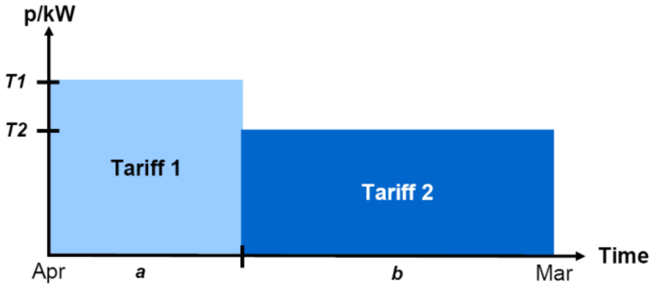
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

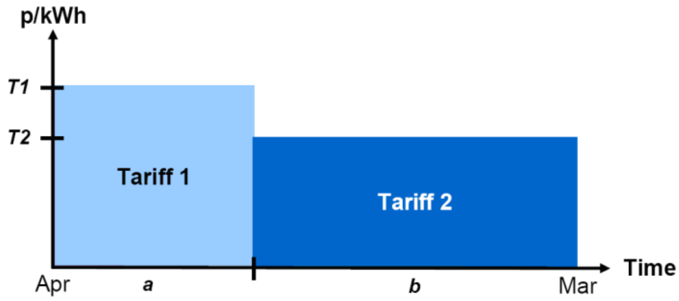
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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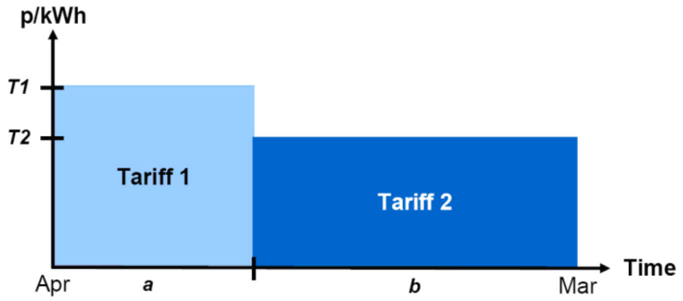
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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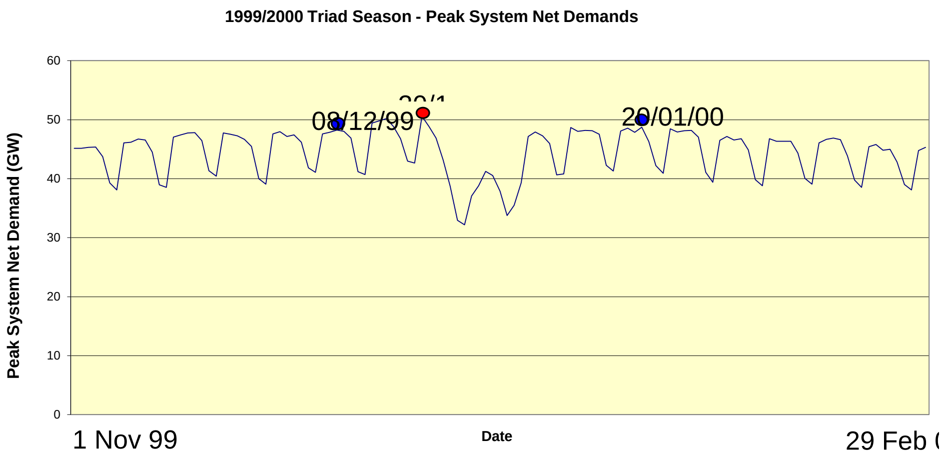


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50,000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

$= (9{,}000kW - 7{,}200kW) \times$ £10.00/kW

$= 1{,}800kW \times$ £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

$= (-500kW - -600kW) \times$ £5.00/kW

$= 100kW \times$ £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

= $\frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

= $\frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 … Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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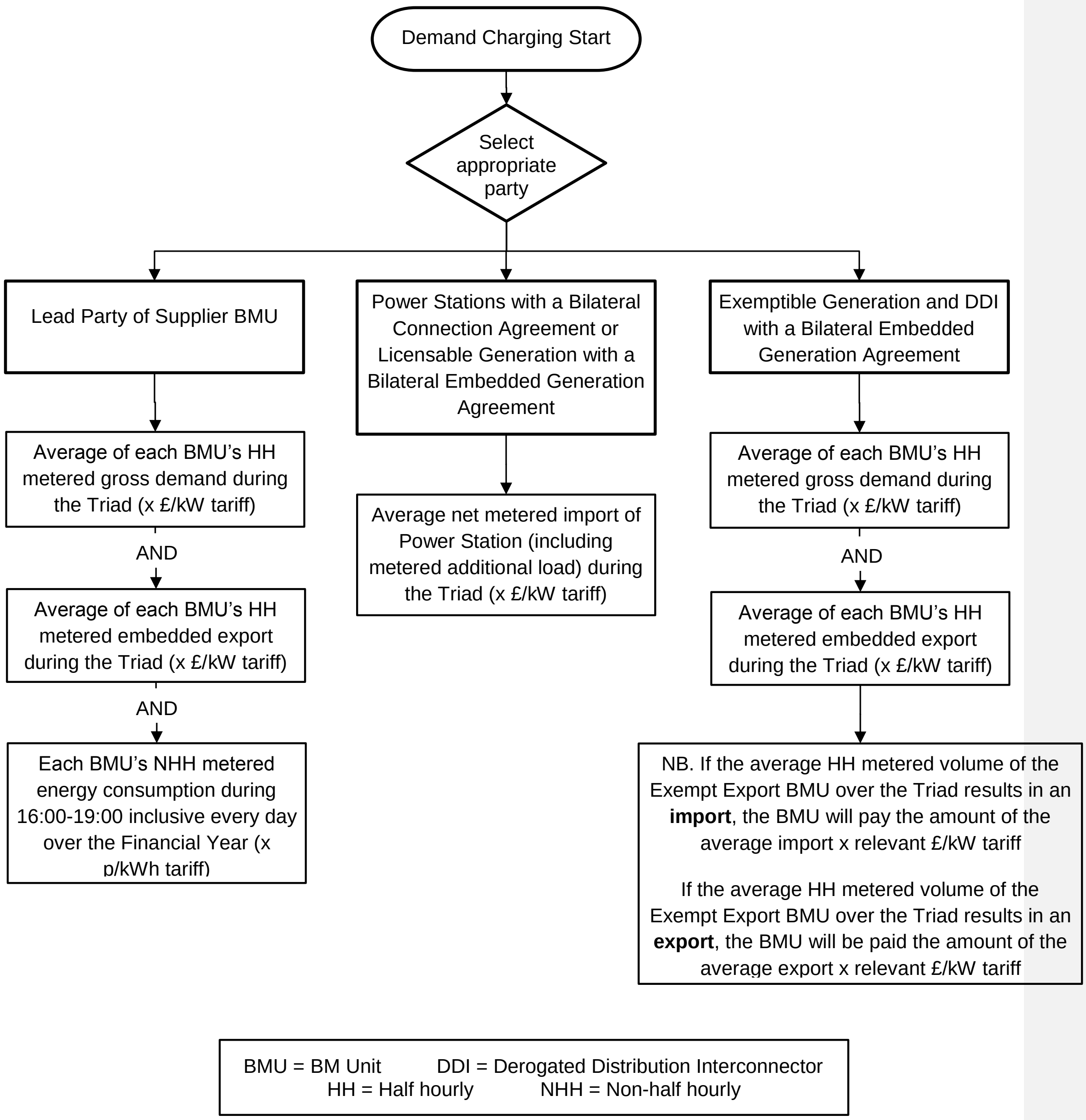
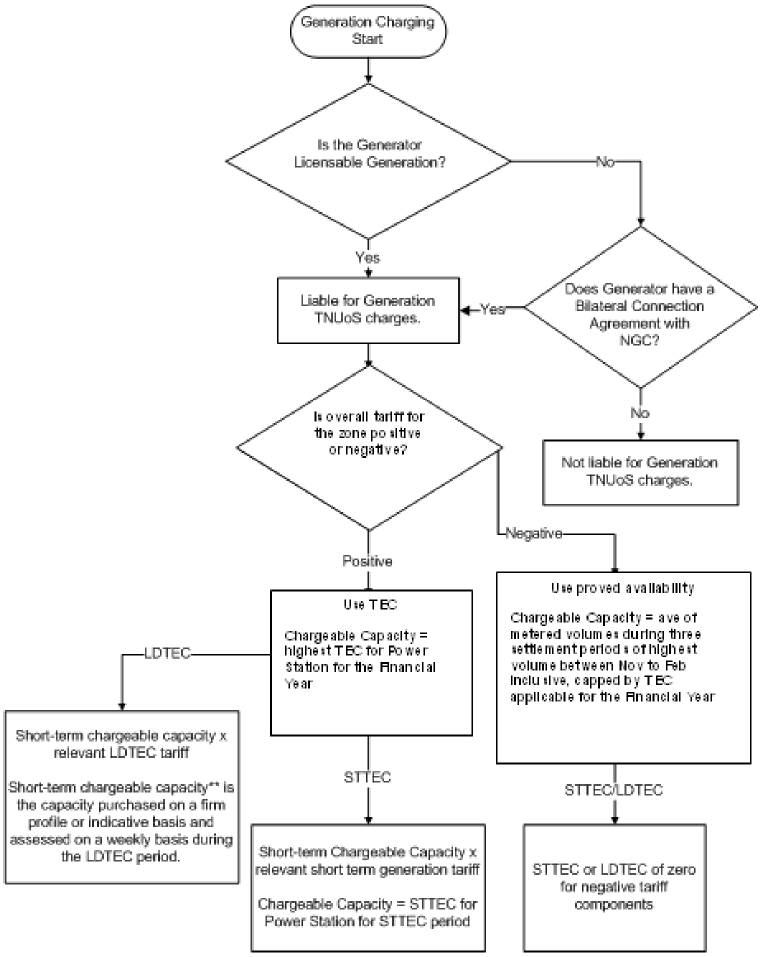


## Generation Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM4

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

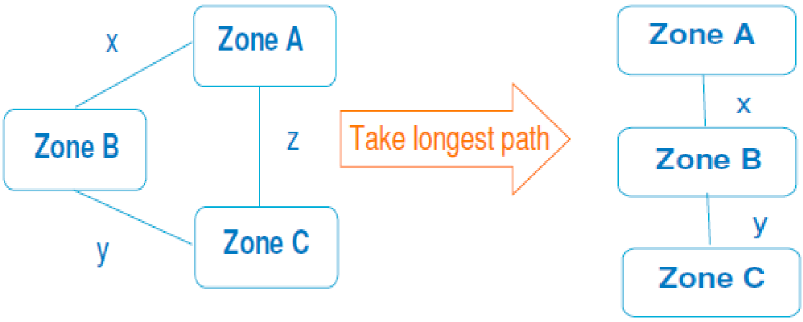
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

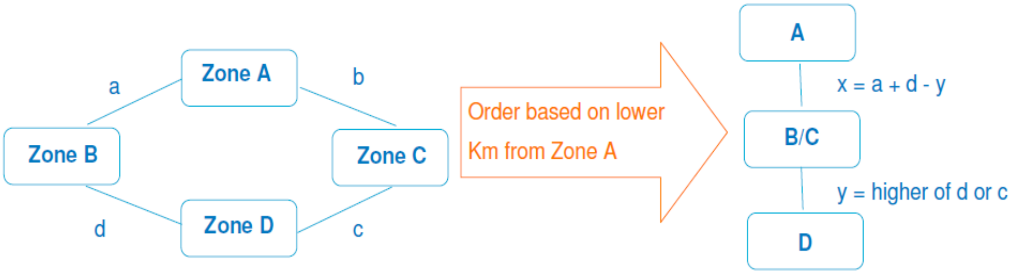
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

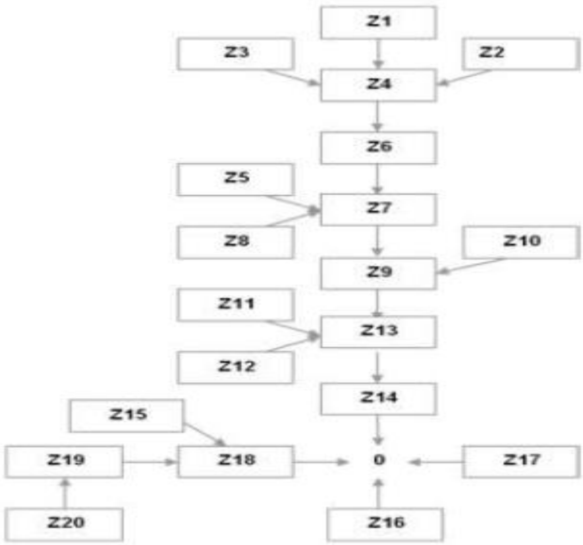
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_B, \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_C - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\text{IRevOFTO} \times \text{NetworkExportCapacity}}{\text{CRevOFTO} \times \sum_{k} \text{Gen}_{k}} + LocalSF_{\text{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$
$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - AGIC) + AGIC$$

Second charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - AGIC) + AGIC$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$= AGIC$$

Where
XP = Value of demand residual in charging year prior to implementation
AGIC = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

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| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{GiYRNS} \times G_{Gi} \right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n} \left( ITT_{GiYRS} \times G_{Gi} \times ALF \right) = ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14} \left( ITT_{DiYR} \times D_{Di} \right) = ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14} (EET_{Di} \times EEV_{Di})$$

Where

| | | |
|---|---|---|
| $ITTR_{EE}$ | = | Initial Revenue impact for Embedded Exports |
| $EEV_{Di}$ | = | Forecast Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $\mathrm{LCRR}_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.132 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

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**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

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$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.142 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the

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marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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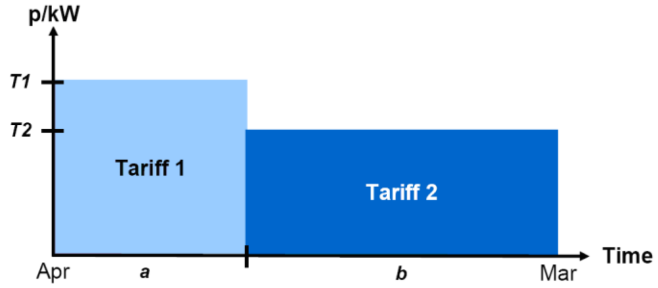
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

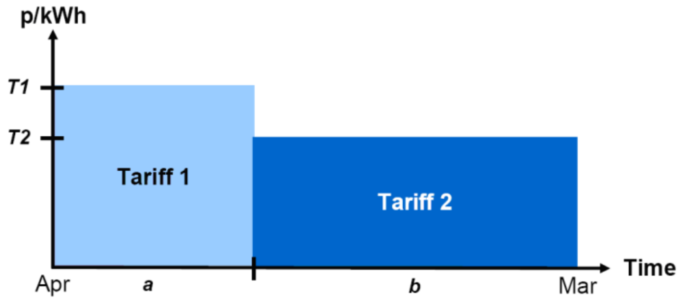
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \begin{matrix}Chargeable\ Embedded\\ Export\ Capacity\end{matrix} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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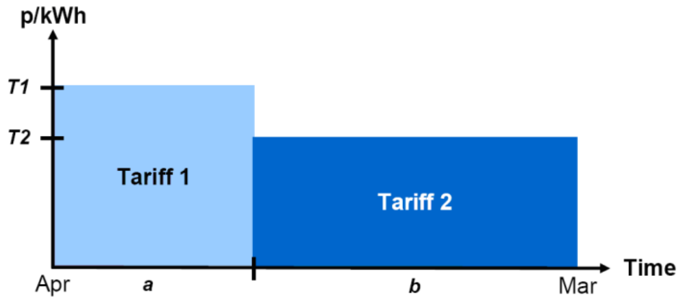
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

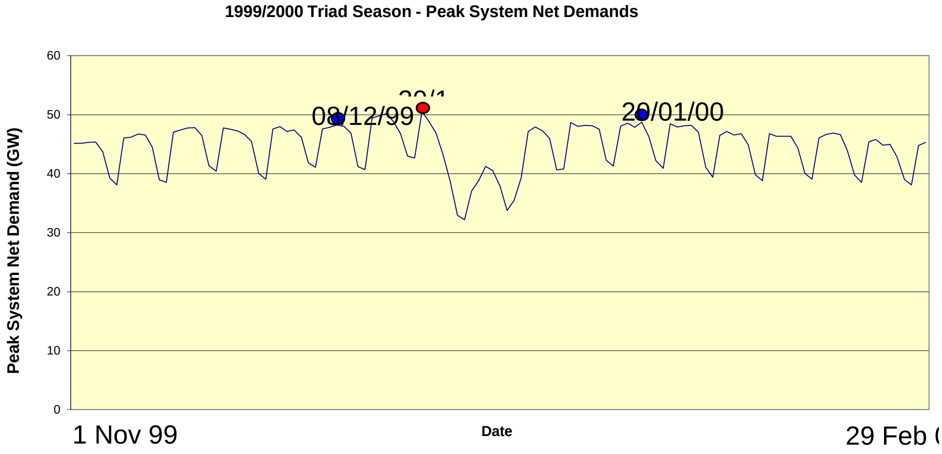
- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.




**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A – HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHD_F}$ = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHEE_A}$ = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{HHEE_F}$ = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{NHHC_A}$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

$\mathbf{NHHC_F}$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><th colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</th></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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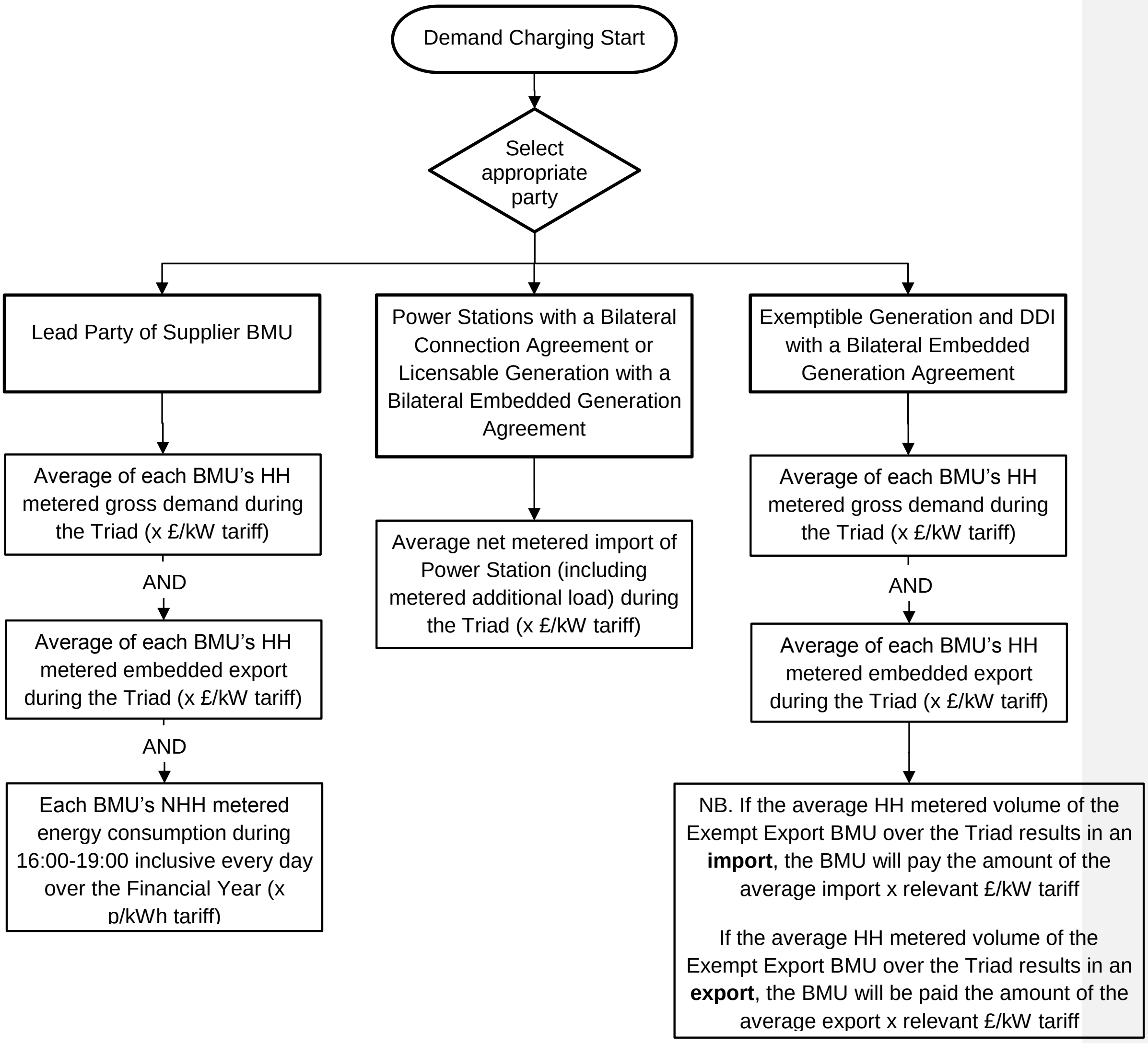
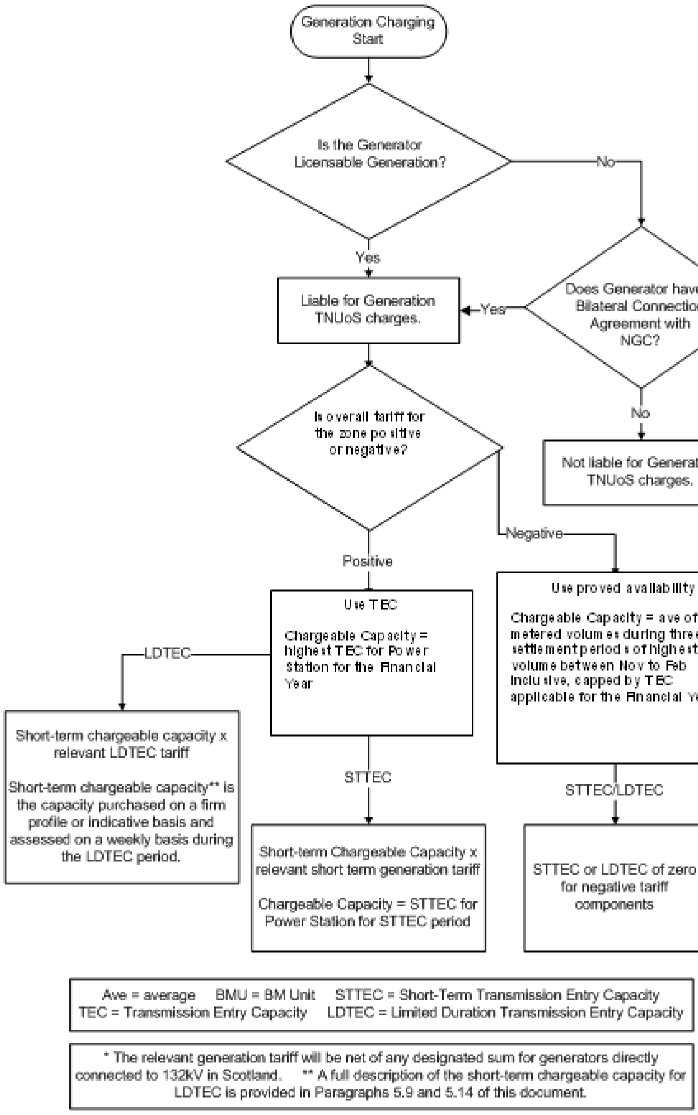



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ June 2005 for the period 1$^{st}$ April 2005 to 31$^{st}$ March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1$^{st}$ April 2004 to 31$^{st}$ March 2005)

D = 4,400,000 kWh (period 1$^{st}$ April 2005 to 15$^{th}$ May 2005#)

P = 4,000,000 kWh (period 1$^{st}$ April 2004 to 15$^{th}$ May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2004 to 31$^{st}$ March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM5

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

## Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

### Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

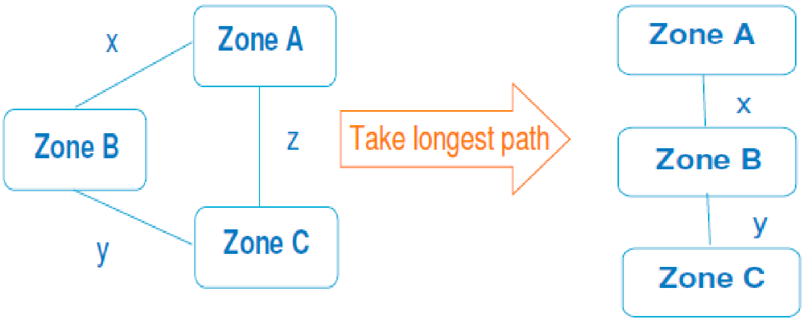
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

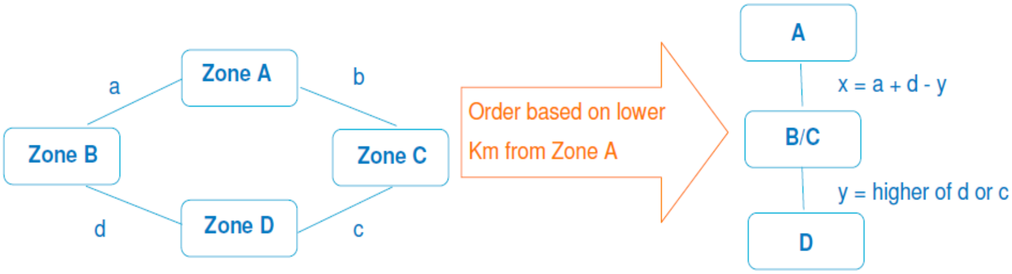
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

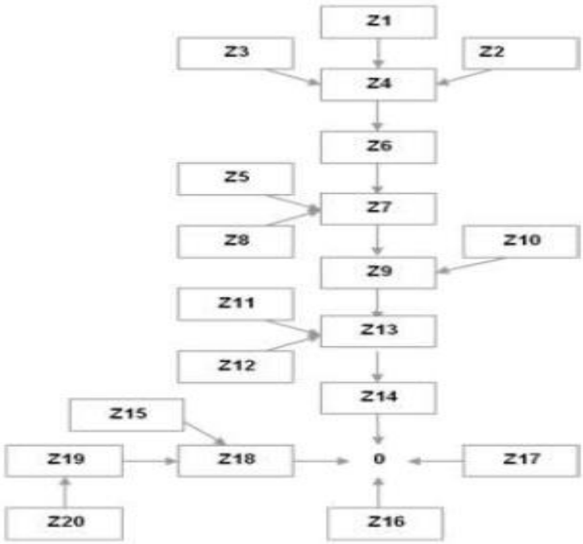
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| **400kV OHL expansion constant calculation** | **Ave £/MWkm** |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$
$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TN

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ((RT_G \times -1) + AGIC)) + ((RT_G \times -1) + AGIC)$$

Second charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ((RT_G \times -1) + AGIC)) + ((RT_G \times -1) + AGIC)$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$= (RT_G \times -1) + AGIC$$

Where
XP = Value of demand residual in charging year prior to implementation
$RT_G$ = Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.
AGIC = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS}\times G_{Gi}\times F_{PS}\right)=ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS}\times D_{Di}\right)=ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{G\,YRNS}$$
$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS}\times G_{Gi}\times ALF\right)=ITRR_{G\,YRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

$k$ = Local circuit $k$ for generator

$NLMkm_{Gj}^{L}$ = Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor.

EC = Expansion Constant

$LocalSF_k$ = Local Security Factor for circuit $k$

$CLT_{Gi}$ = Circuit Local Tariff (£/kW)

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
LCRR$_G$ = Local Charge Revenue Recovery
G$_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.132 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:
SLT$_k$ = the offshore substation tariff for substation k
Gen$_k$ = the generation connected to offshore substation k

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**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$



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$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.142 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the

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marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff} \quad (\text{£/kW/period})$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{\text{Chargeable Gross Demand Capacity}} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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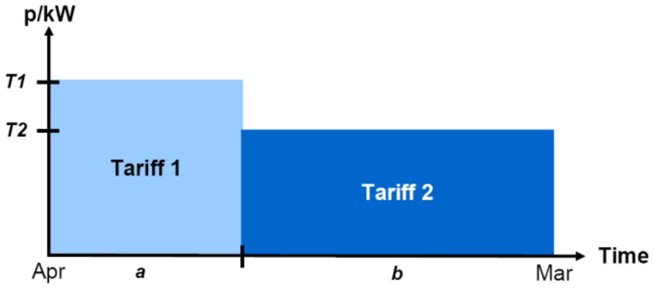
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

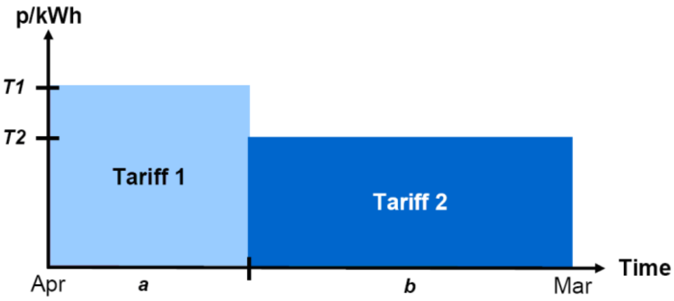
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

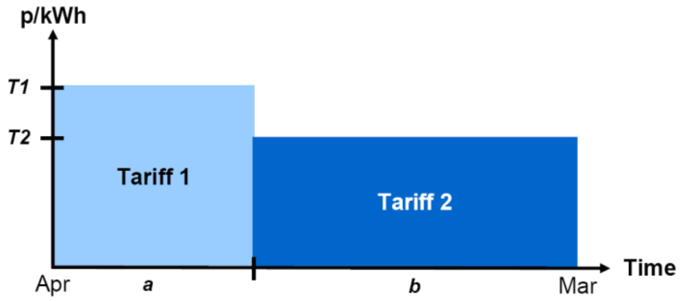
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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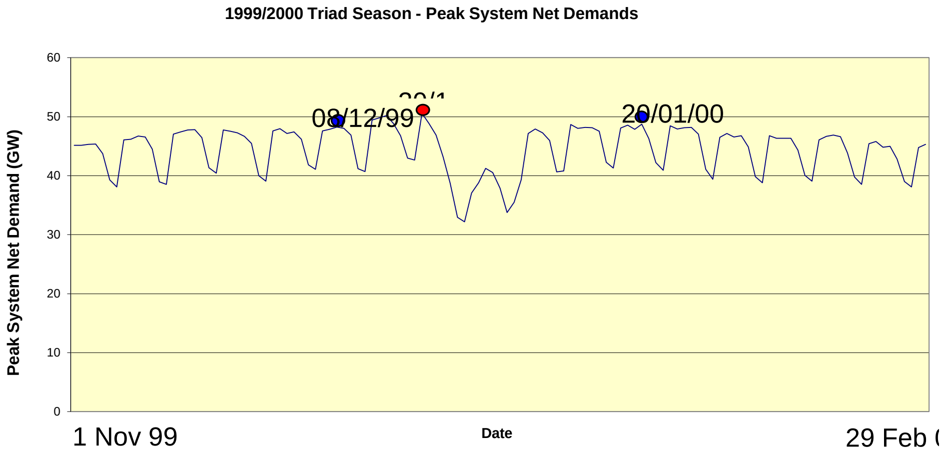


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:
- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} \times £10.07/\text{MWkm} \times 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A – HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17,000,000kWh - 18,000,000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1,000,000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16,700,000kWh – 17,000,000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHD_F}$ = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHEE_A}$ = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{HHEE_F}$ = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{NHHC_A}$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

$\mathbf{NHHC_F}$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| **PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT** | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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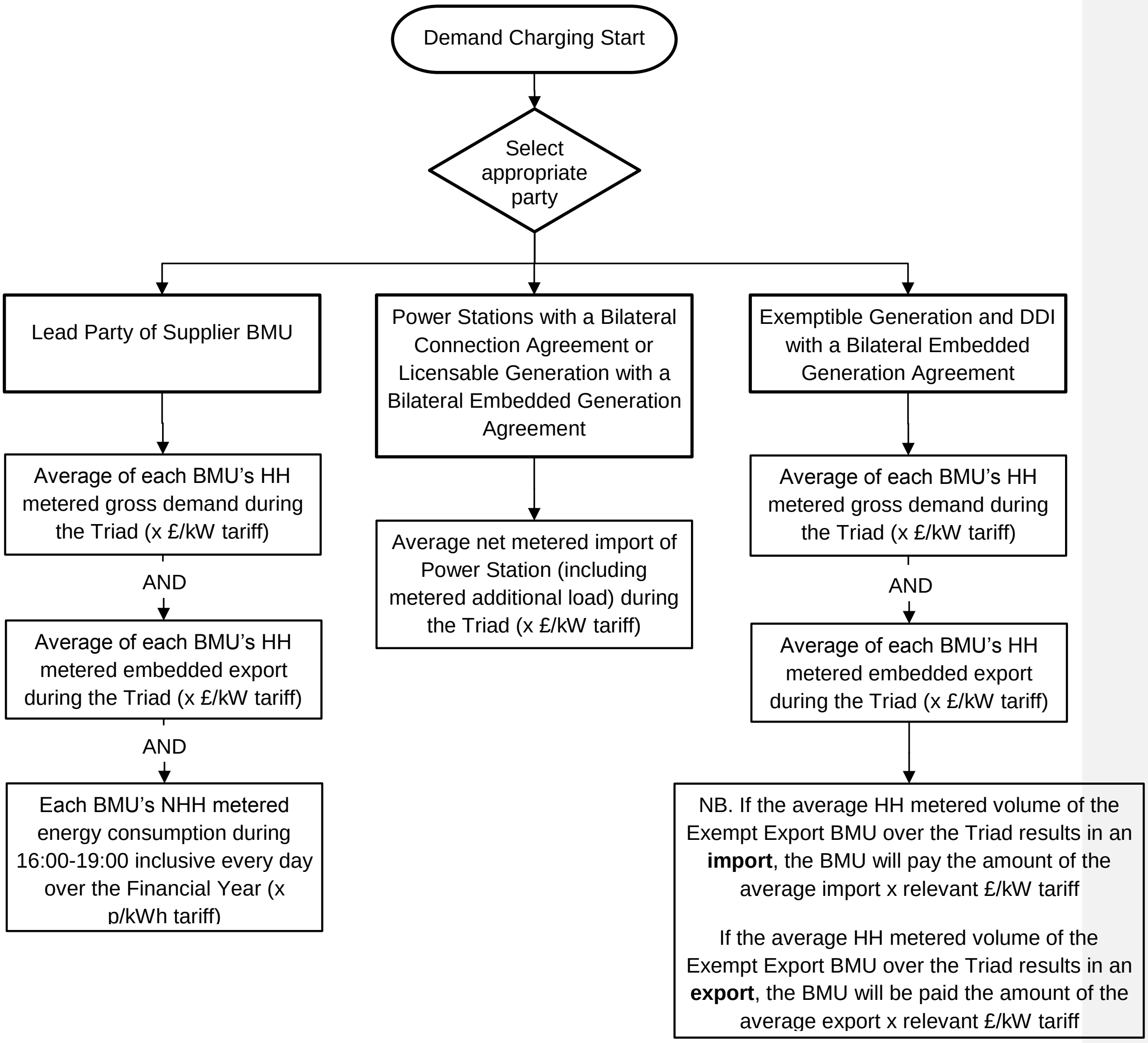
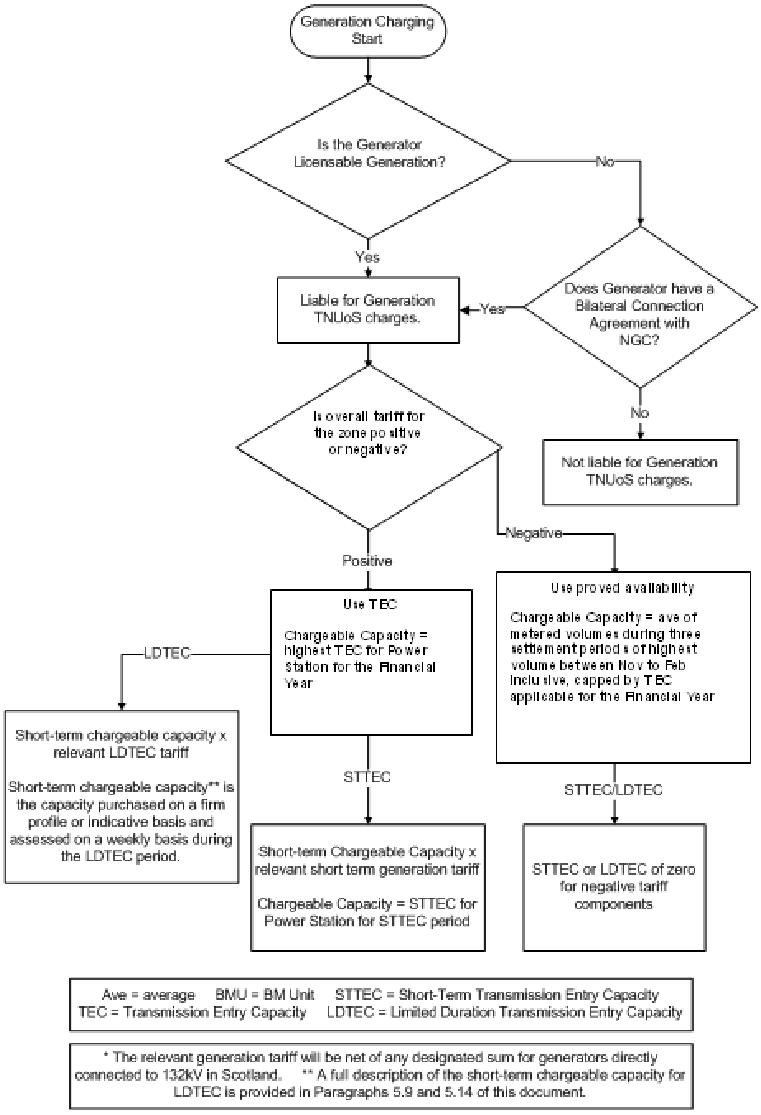



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at $10^{th}$ March 2005 for the period $1^{st}$ April 2005 to $31^{st}$ March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period $1^{st}$ April 2004 to $15^{th}$ February 2005#)

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P = 12,000 kW (period $1^{st}$ April 2003 to $15^{th}$ February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period $1^{st}$ April 2004 to $15^{th}$ February 2005#)

P = -350 kW (period $1^{st}$ April 2003 to $15^{th}$ February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

Deleted: h

Deleted: h

Deleted: h

Deleted: h

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM6

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

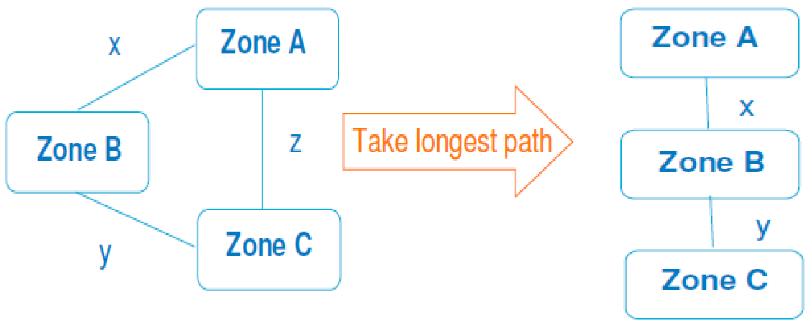
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

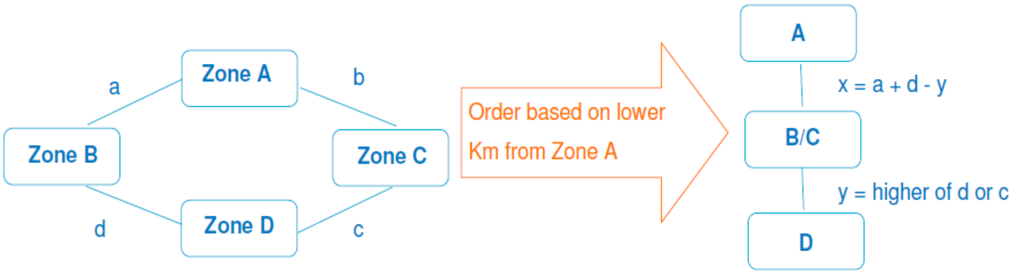
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

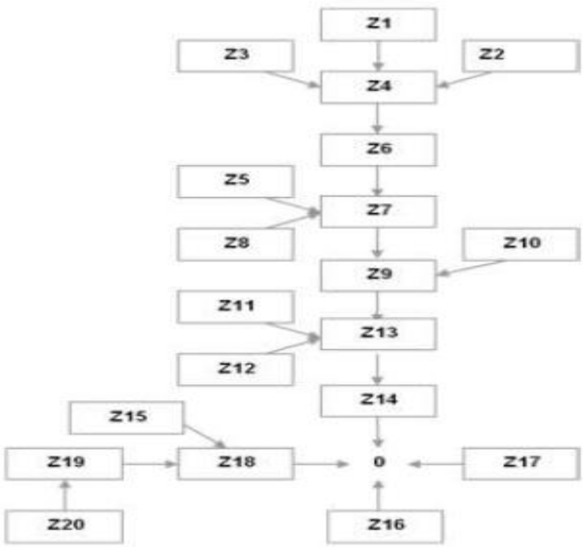
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\, 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\, 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = $ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

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***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the

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relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$



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$RT_D = \frac{(p\times TRR) - I}{}$

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14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit

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amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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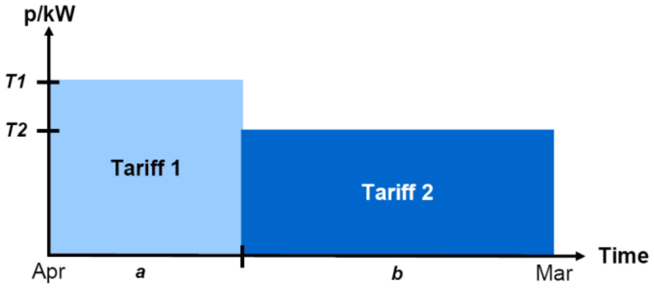
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

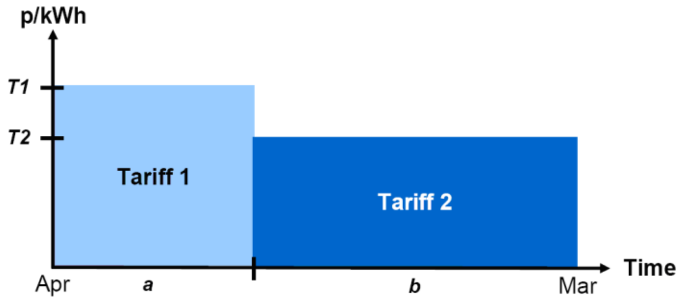
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

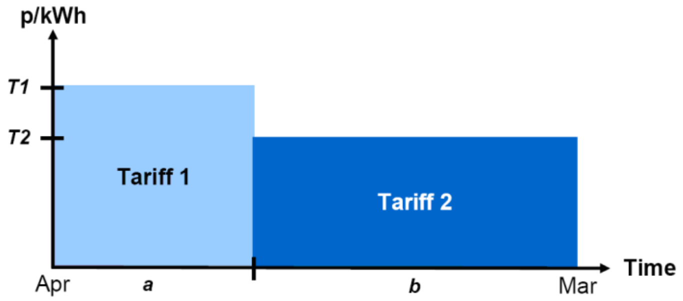
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

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**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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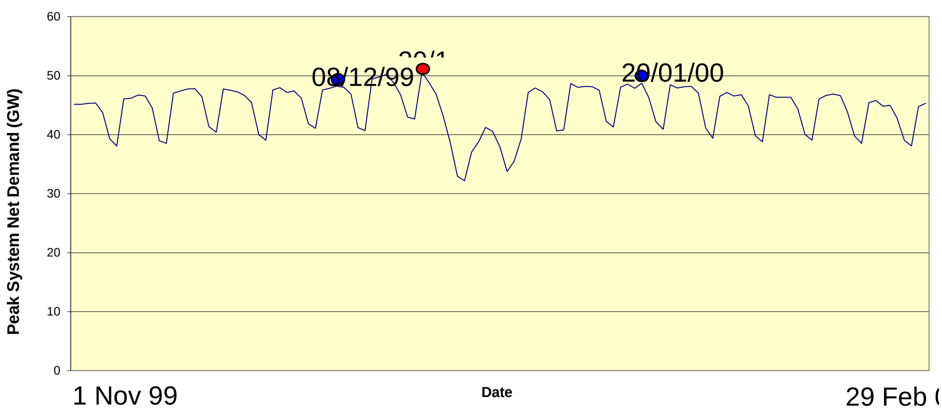
**1999/2000 Triad Season - Peak System Net Demands**




**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A - HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = (NHHC$_A$ - NHHC$_F$) x p/kWh Tariff

100

= (17,000,000kWh - 18,000,000kWh) x 1.20p/kWh

100

= -1,000,000kWh x 1.20p/kWh
100

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = (16,700,000kWh – 17,000,000kWh) x 1.20p/kWh
100
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**HHD$_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| SUPPLIER | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| POWER STATION WITH A BILATERAL CONNECTION AGREEMENT | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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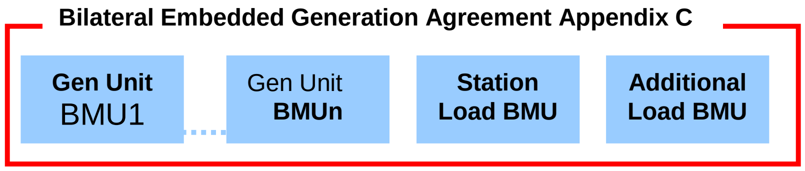
| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
|  | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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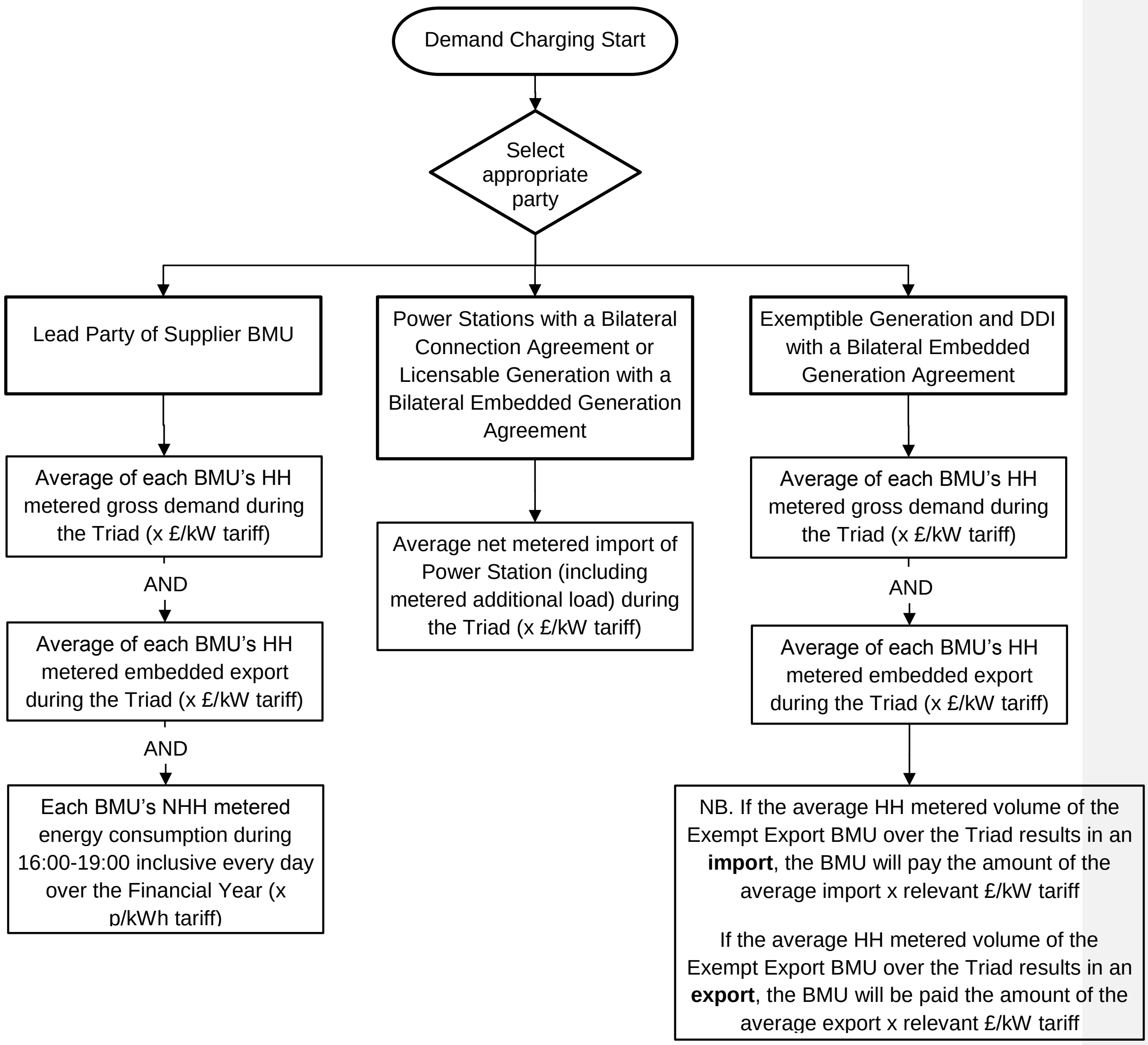
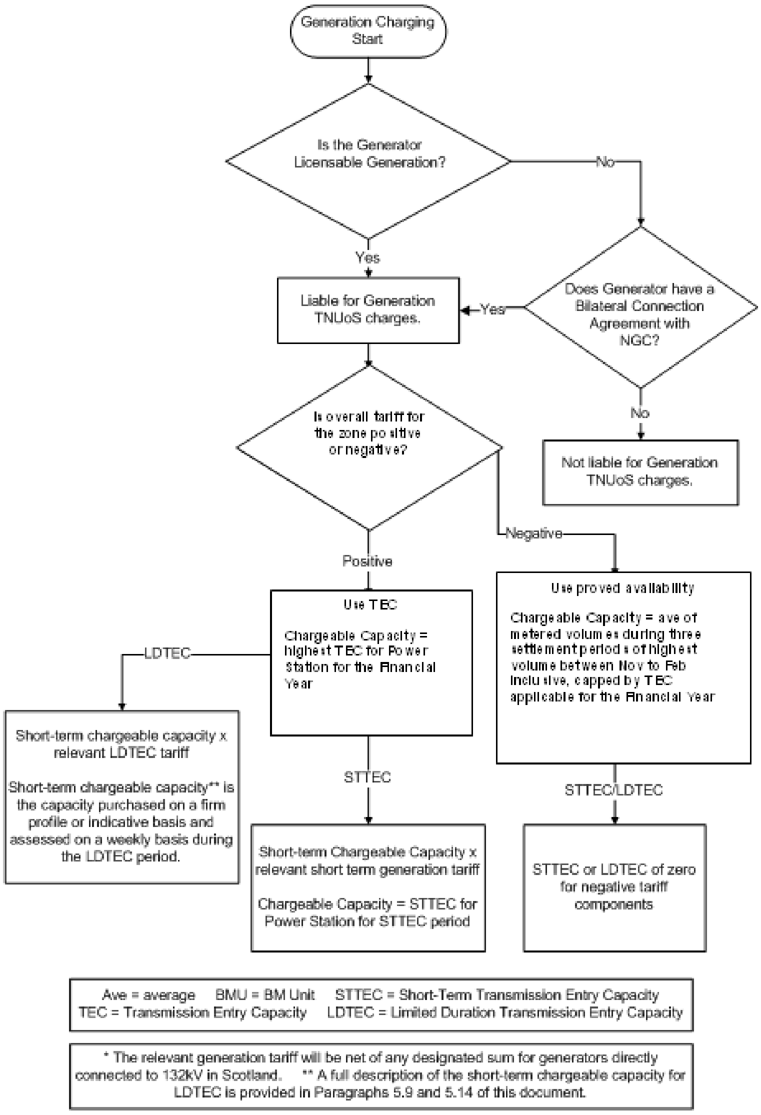



BMU = BM Unit    DDI = Derogated Distribution Interconnector
HH = Half hourly    NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

$F = T * D/P$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| **Generation Plant Type** | **Peak Security Background** | **Year Round Background** |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

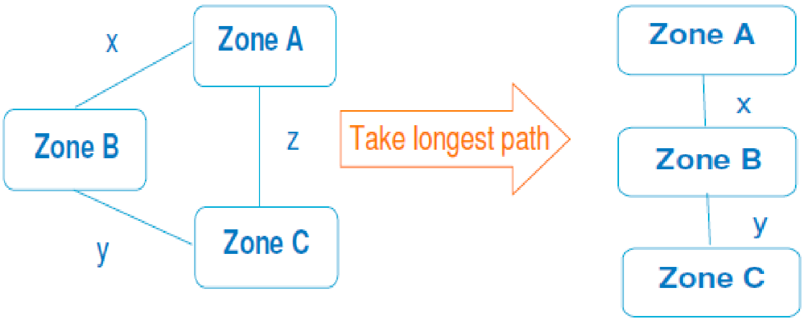
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

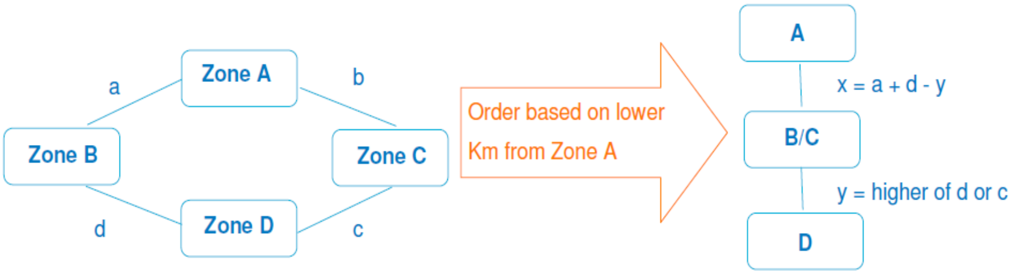
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

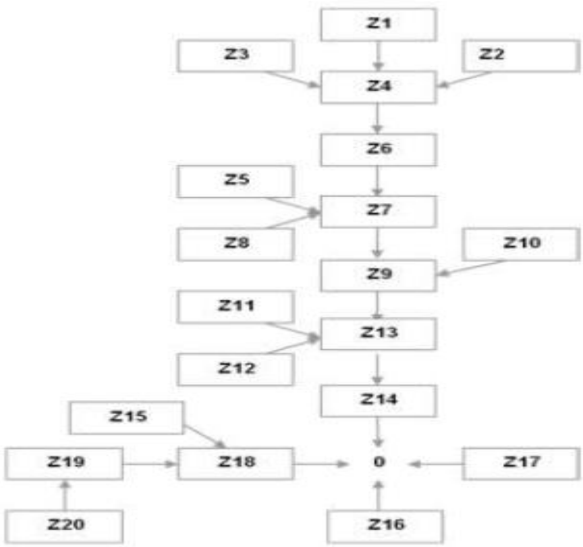
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$ = Peak Security Zonal Marginal km for each demand zone

$ZMkm_{DiYR}$ = Year Round Zonal Marginal km for each demand zone

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each demand one

$ITT_{DiYR}$ = Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$ITRR_D$ = Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts).

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX:
First Charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))) + ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$$

Second charging year following the implementation date of CMP 264/265:

$$= \frac{2}{3}(XP - ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))) + ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$$

Third charging year following the implementation date of CMP 264/265 and every subsequent charging year:

$$= ABs\,(Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$$

Where
XP = Value of demand residual in charging year prior to implementation

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where
$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}\left(EET_{Di} \times EEV_{Di}\right)$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ (MW) = Forecast Embedded Export metered volume at Triad

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period. Deleted: 119

14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components: Deleted: 120

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs: Deleted: 121
$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability. Deleted: 122

$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by: Deleted: 123

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components. Deleted: 124

14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under |

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

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Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag

- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Gross Demand Capacity} \times \left( \frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12} \right)$$

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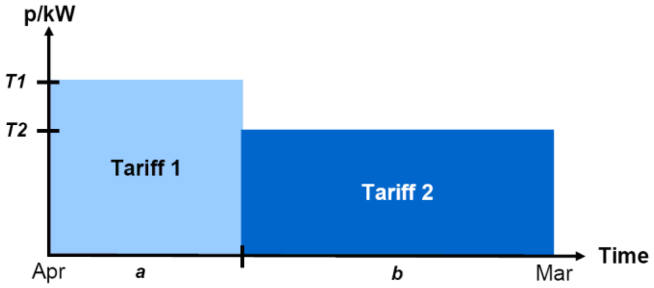
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

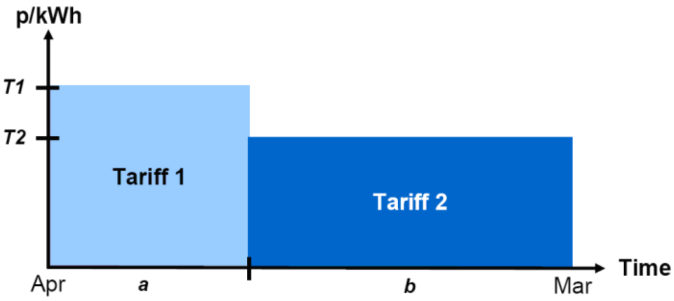
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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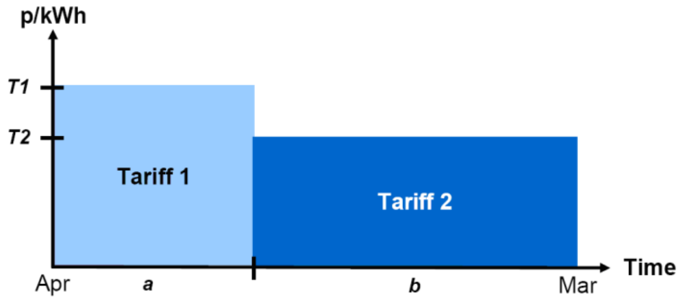
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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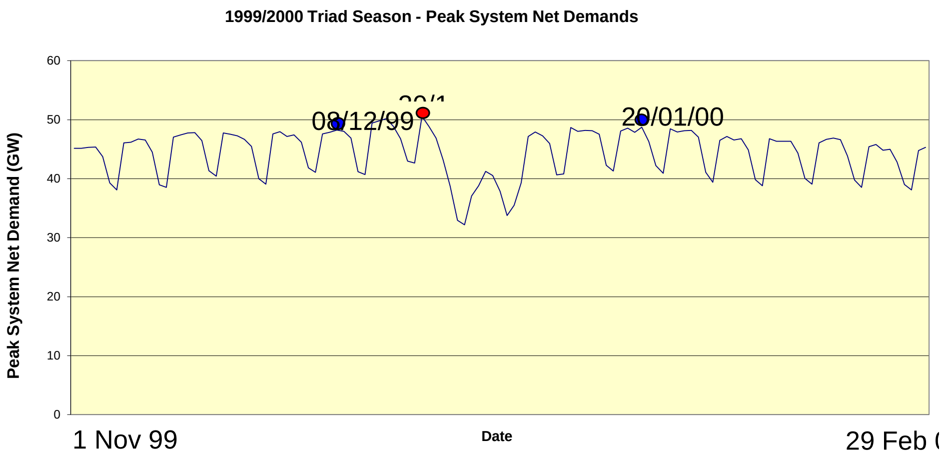


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

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14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:
- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A – HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= (17,000,000kWh - 18,000,000kWh) x 1.20p/kWh / 100

= -1,000,000kWh x 1.20p/kWh / 100

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = (16,700,000kWh – 17,000,000kWh) x 1.20p/kWh / 100
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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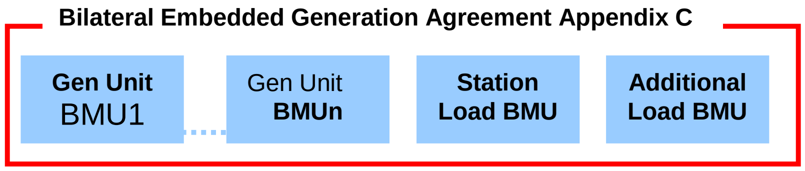
| **PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT** | |
|---|---|
|  | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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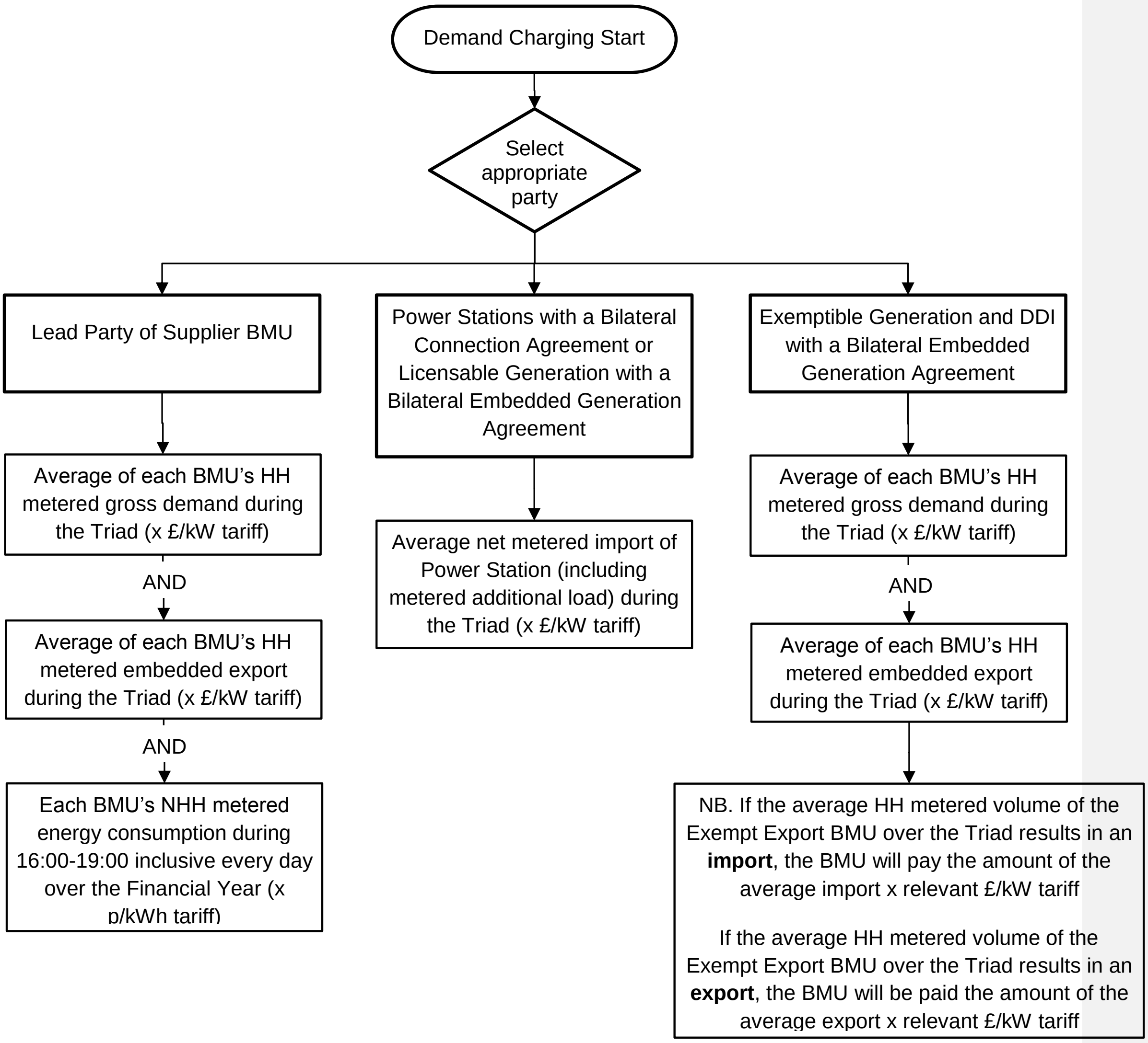
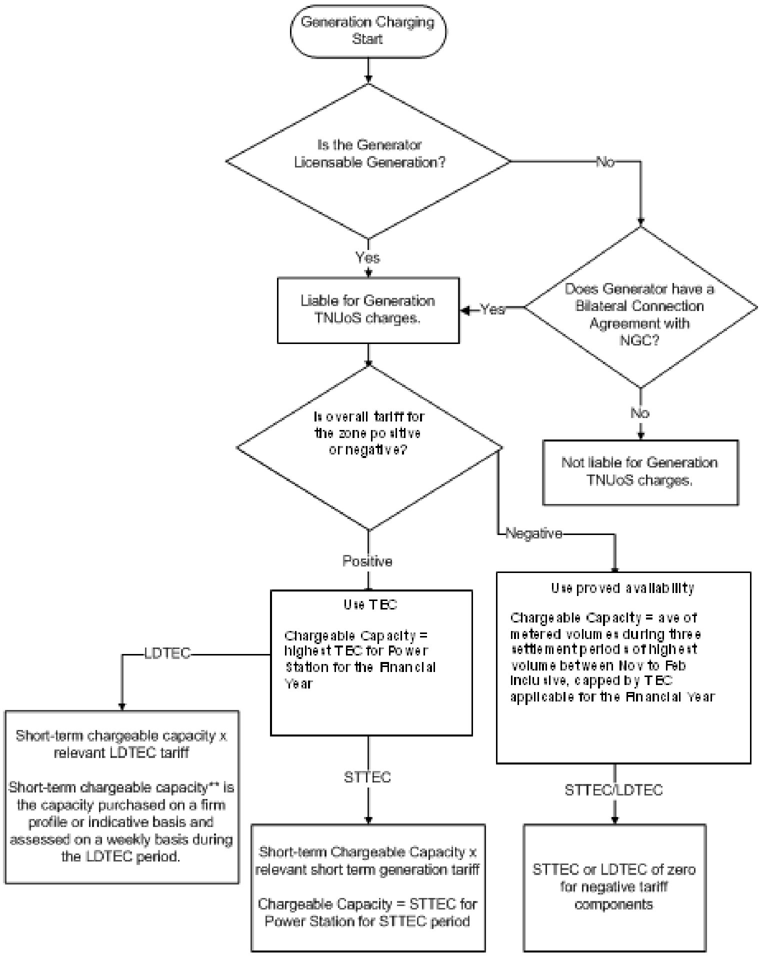



BMU = BM Unit  DDI = Derogated Distribution Interconnector
HH = Half hourly  NHH = Non-half hourly

Generation
Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

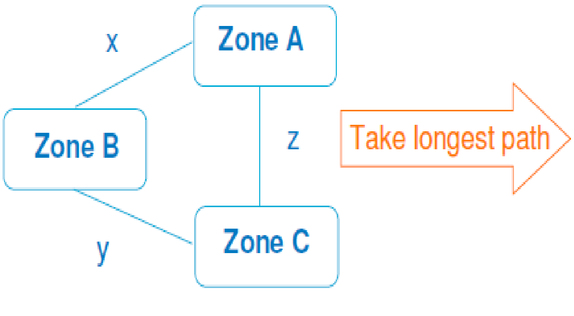
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

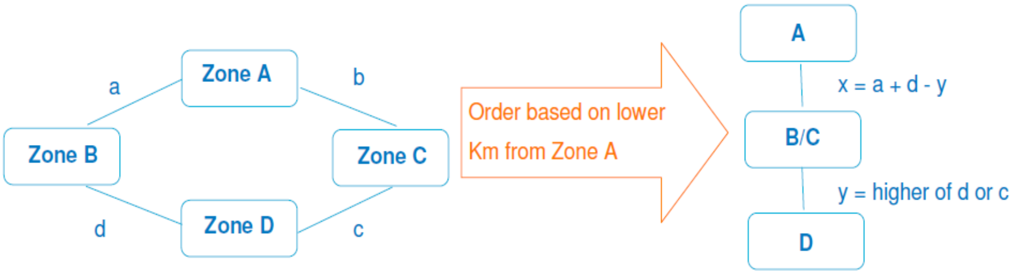
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

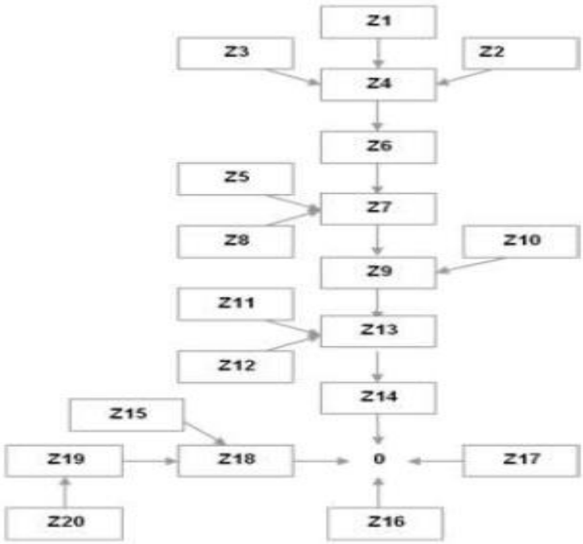
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = £32.30 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

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14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}\left(EET_{Di} \times EEV_{Di}\right)$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

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14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:
$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

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14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

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14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_G = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

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**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of

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time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{\left[(1-p) \times TRR\right] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

### Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

| | | |
|---|---|---|
| $NRRT_D$ | = | Non Recovered Revenue Tariff (£/kW) |
| $RFT_{Di}$ | = | Revised Final Tariff (£/kW) |

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum,

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determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} *100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

### Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

### Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

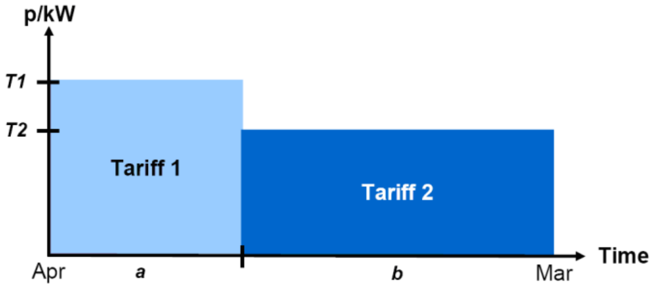
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

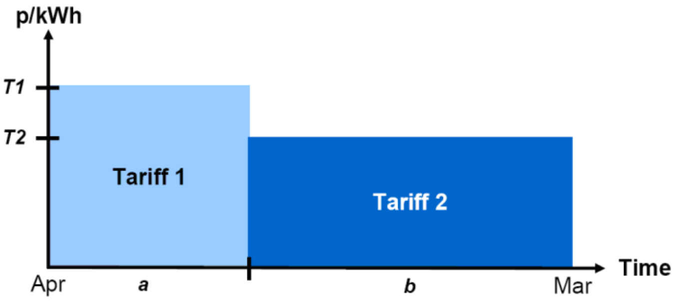
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$\text{Annual Liability}_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Annual Liability $_{D}$
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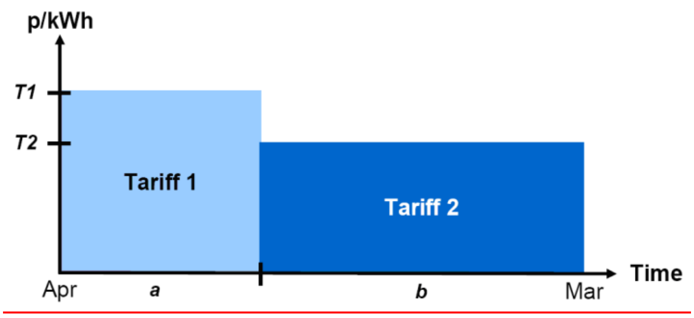
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.



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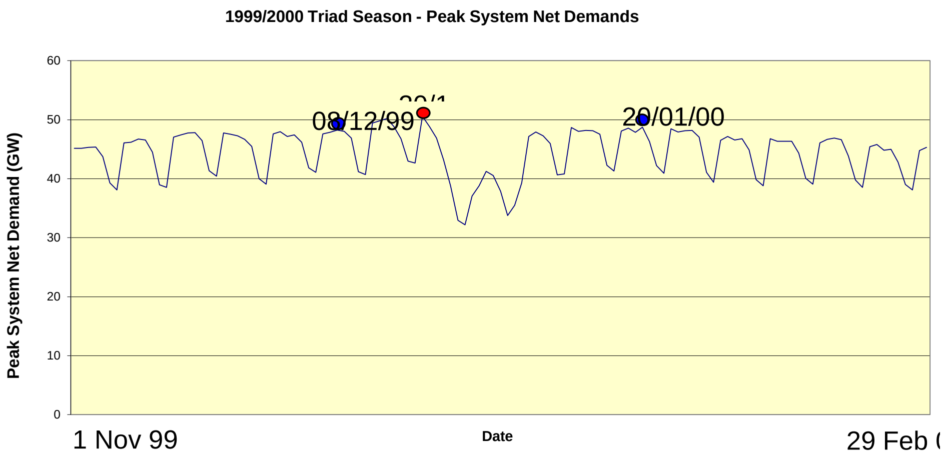


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

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If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

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- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

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- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

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b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\textbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

$= (9{,}000kW - 7{,}200kW) \times$ £10.00/kW

$= 1{,}800kW \times$ £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

$= (-500kW - -600kW) \times$ £5.00/kW

$= 100kW \times$ £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh - 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| SUPPLIER | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| POWER STATION WITH A BILATERAL CONNECTION AGREEMENT | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** / **Station Load BMU** / **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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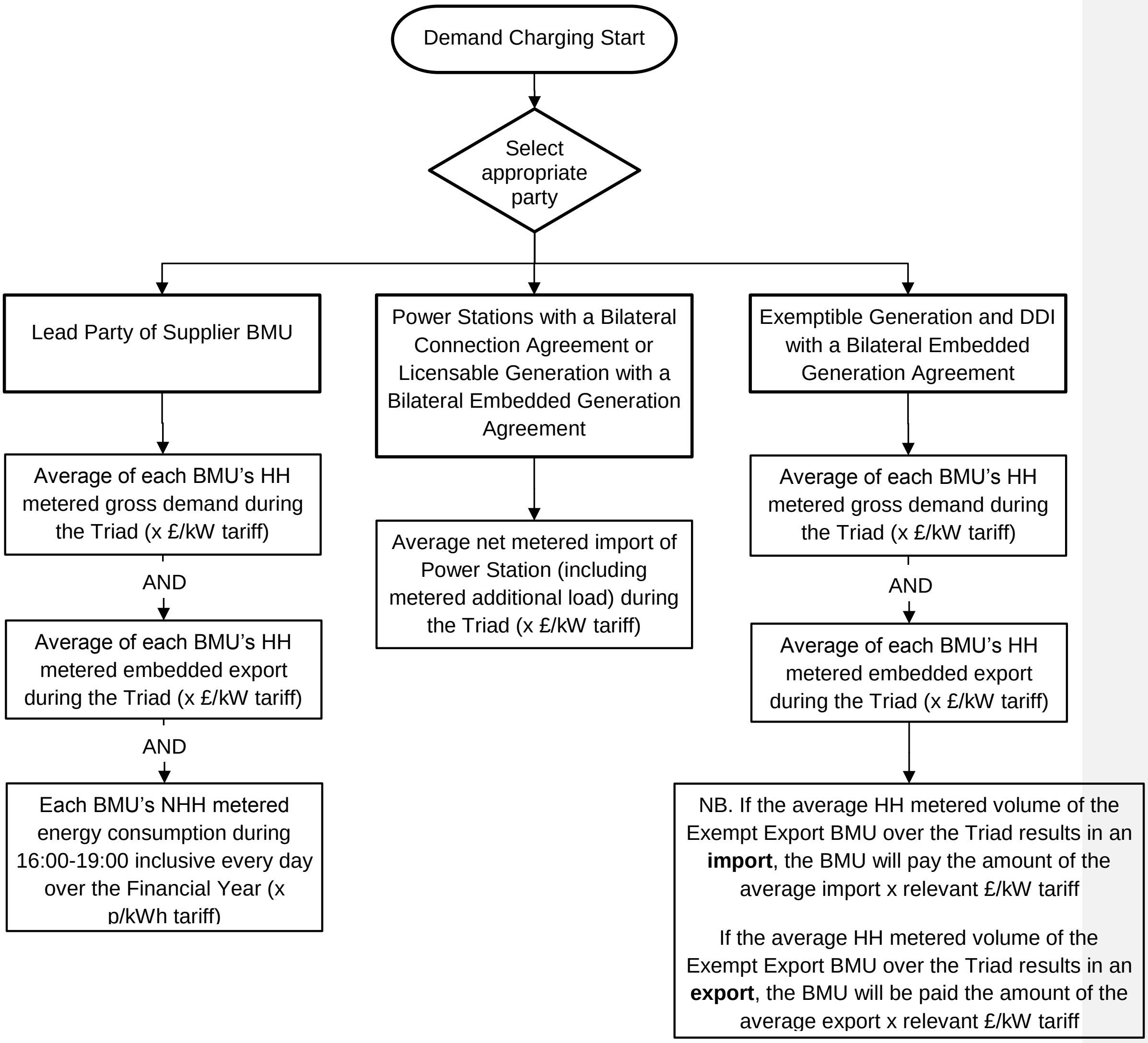
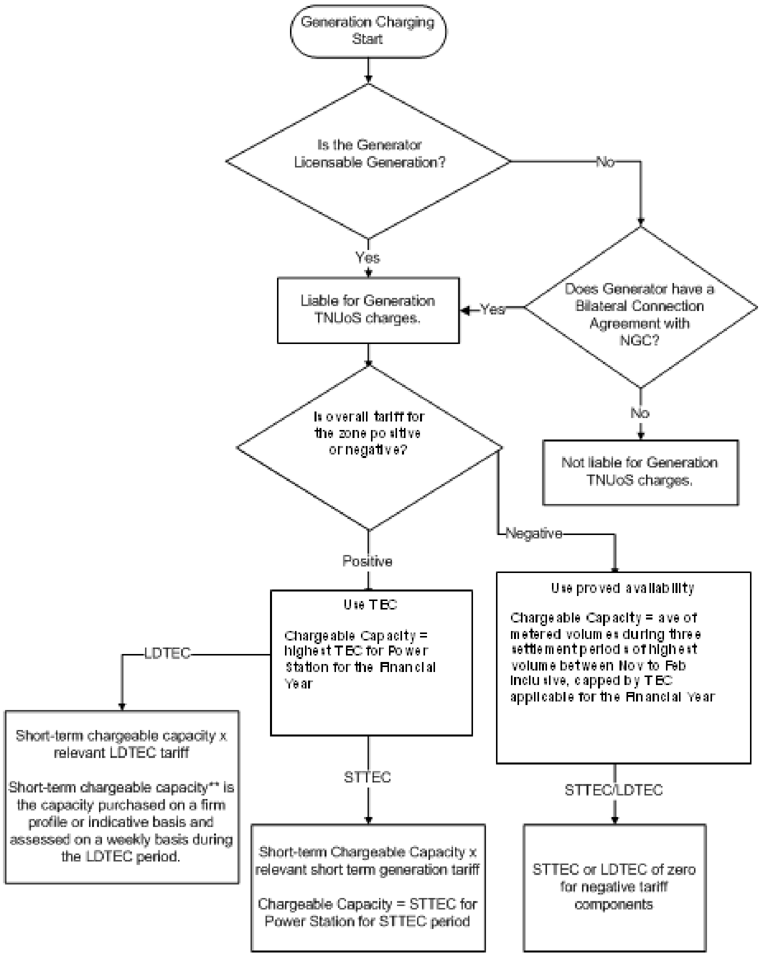



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

Deleted: h

where:

T = 10,000 kW (period November 2003 to February 2004)

Deleted: h

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

Deleted: h

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

Deleted: h

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F =  900 kW

where:

M =  1,000 kW (period 1st July 2005 to 31st July 2005)

T =  17,000,000 kW (period November 2004 to February 2005)

W =  18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F =  150 * 7,200,000 / 6,000,000

F =  180 kW

where:

M =  150 kW (period 1st July 2005 to 31st July 2005)

T =  7,200,000 kW (period November 2004 to February 2005)

W =  6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F =  J + (M * R/W)

Deleted: h

Deleted: h

Deleted: h

Deleted: h

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM9

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_{b} - ZIkm_{a}$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

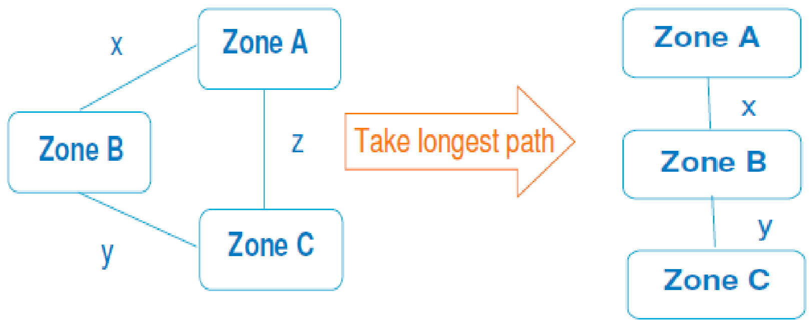
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

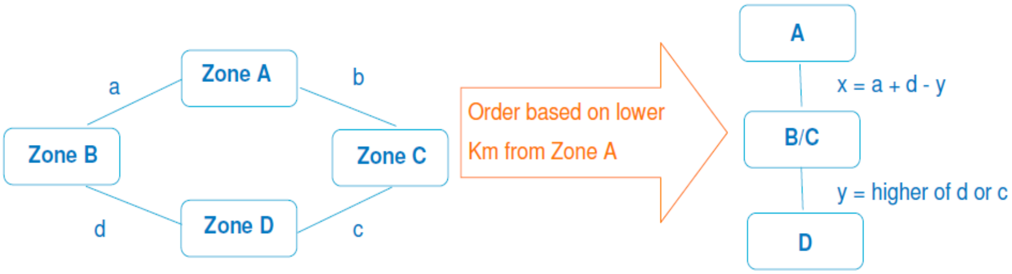
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

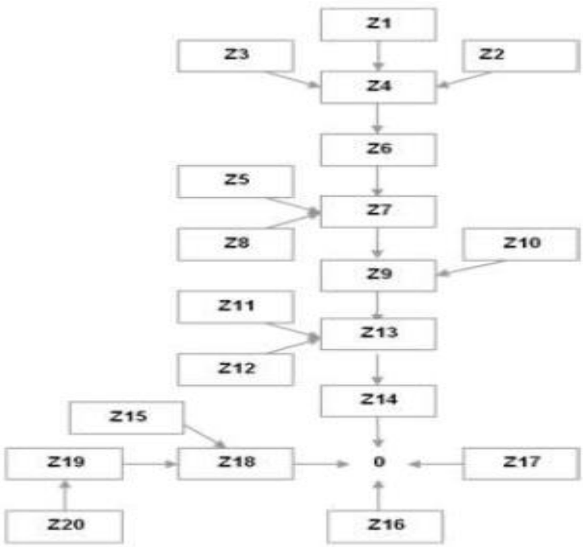
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ <u>then the BSF is calculated using the following formula: -</u>

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\dfrac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner’s reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = For the first charging year following implementation, £34.11 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.
In every subsequent charging year, AGIC + (£18.50 in April 2019 prices; indexed each year by the RPI formula set out in 14.3.6).

Where
AGIC= The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where
$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type

n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}(ITT_{DiPS} \times D_{Di}) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}(ITT_{GiYRNS} \times G_{Gi}) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}(ITT_{GiYRS} \times G_{Gi} \times ALF) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

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$$\sum_{Di=1}^{14}(ITT_{DiYR} \times D_{Di}) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14} (EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ (MW) = Forecast Embedded Export metered volume at Triad

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

### Deriving the Final Local Tariff (£/kW)

#### *Local Circuit Tariff*

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

### Onshore Local Substation Tariff

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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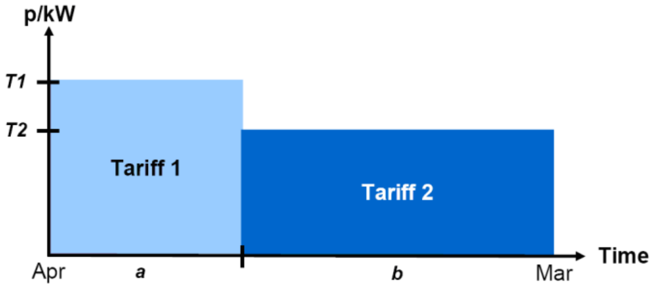
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

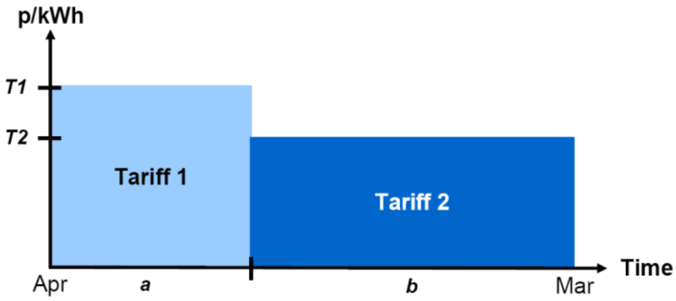
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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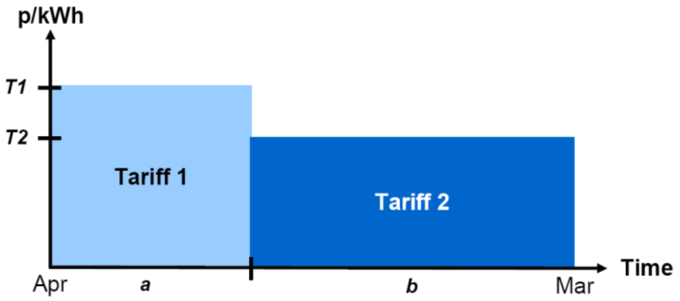
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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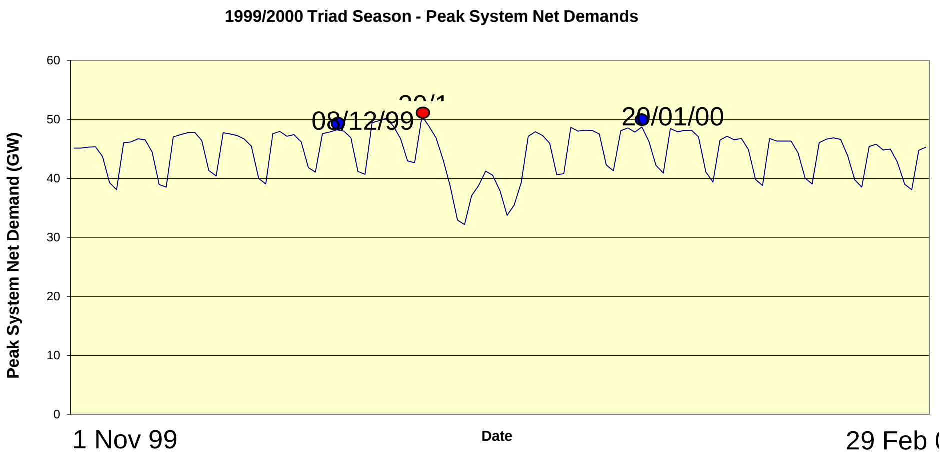


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \textbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A – HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

Deleted: Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= (17,000,000kWh - 18,000,000kWh) x 1.20p/kWh / 100

= -1,000,000kWh x 1.20p/kWh / 100

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = (16,700,000kWh – 17,000,000kWh) x 1.20p/kWh / 100
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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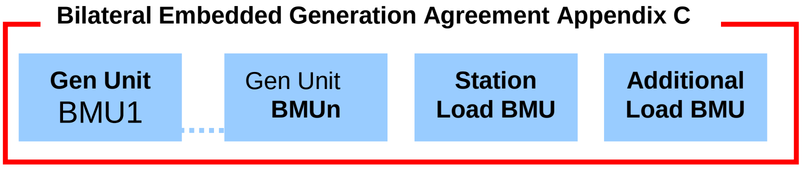
<table>
<tr><th colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</th></tr>
<tr><td colspan="2">
</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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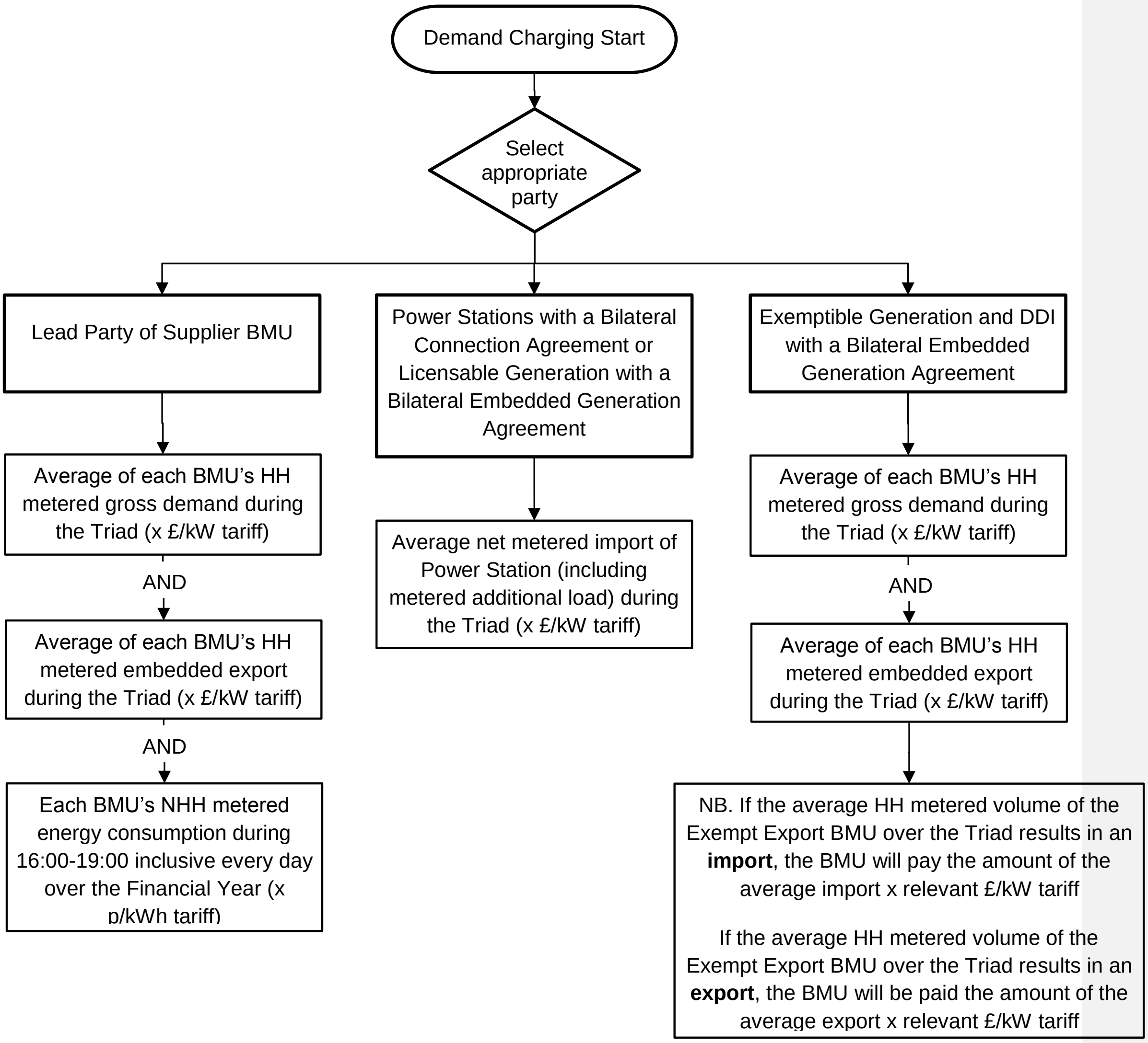
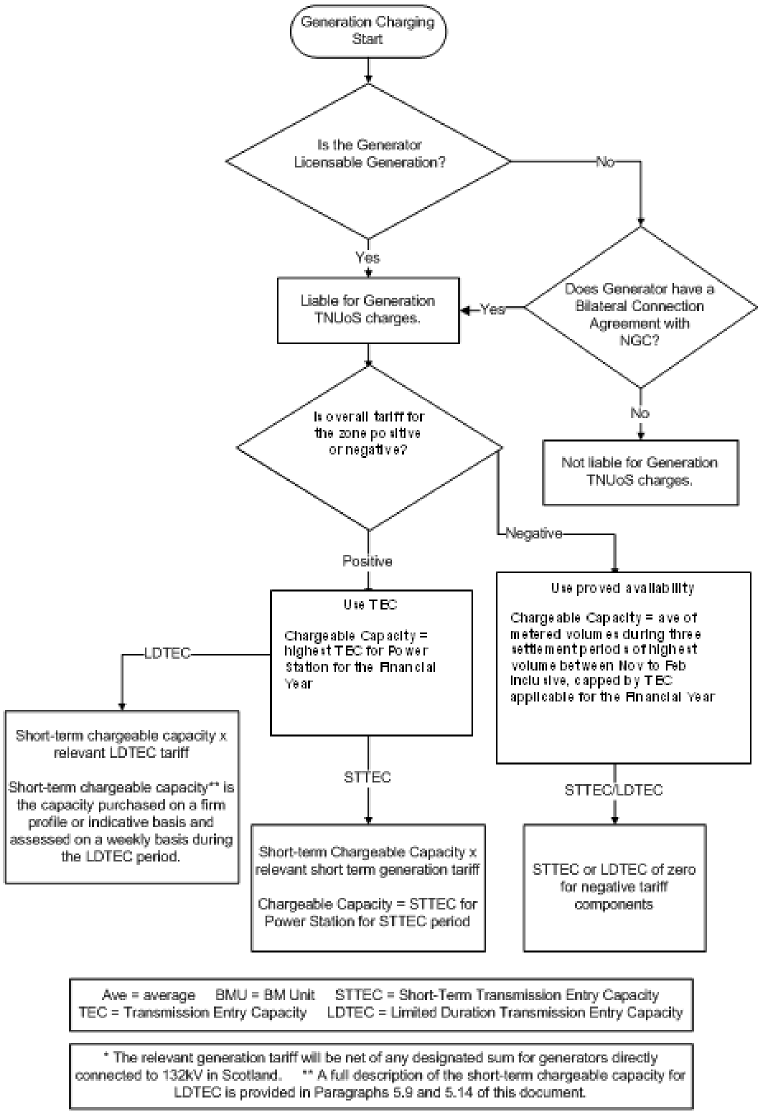



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

## Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

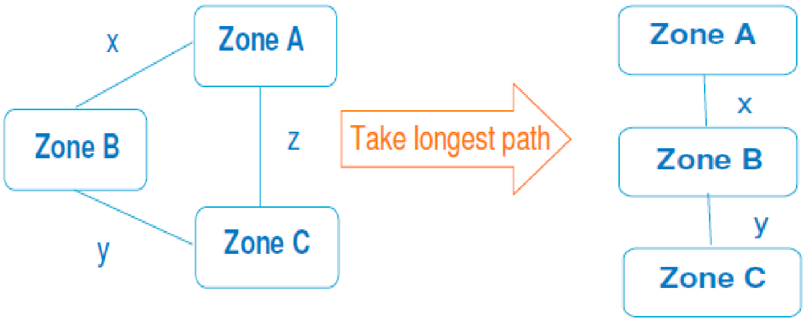
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

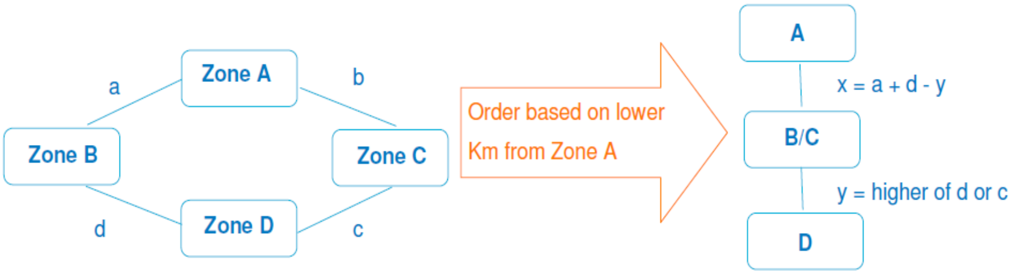
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

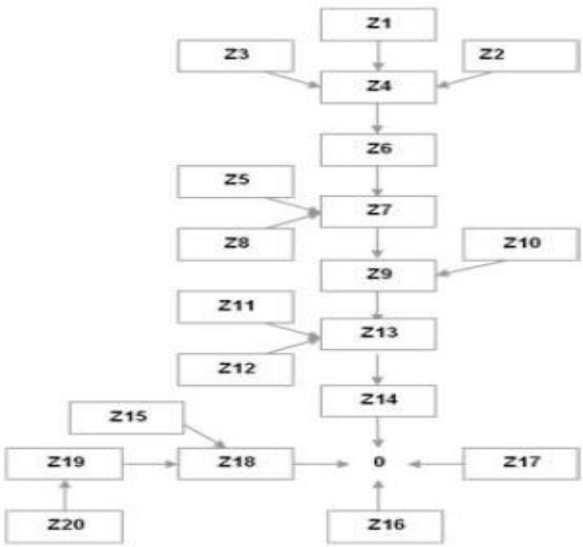
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and

ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:

$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:

$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:

$\min\{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) \}$

and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX = £45.33 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where
$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)



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14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}\left(EET_{Di} \times EEV_{Di}\right)$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

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**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where

| | | |
|---|---|---|
| $ELT_{Gi}$ | = | Effective Local Tariff (£/kW) |
| $SLT_{Gi}$ | = | Substation Local Tariff (£/kW) |

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$

Where

$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:

b = number of months the revised tariff is applicable for

FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $LCRR_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

$SLT_k$ = the offshore substation tariff for substation k

$Gen_k$ = the generation connected to offshore substation k

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of

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time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

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$$RT_D = \frac{(p \times TRR) - I}{}$$

## Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where

$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum,

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determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

### Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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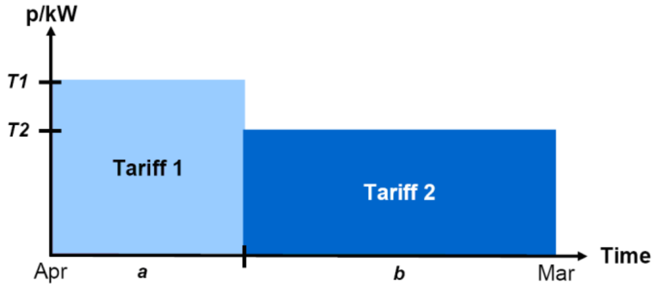
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ \ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ \ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

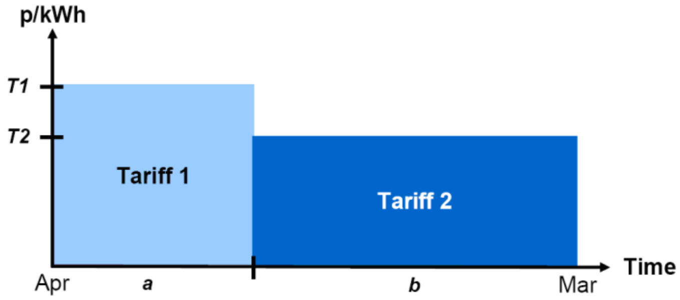
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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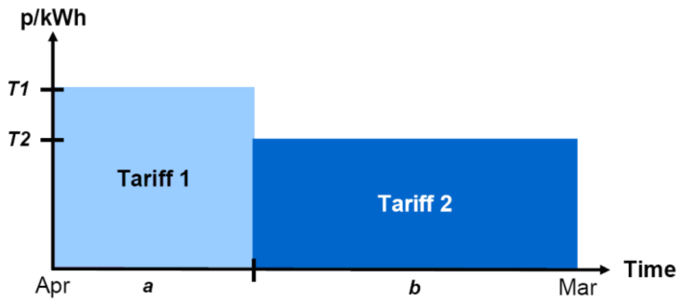
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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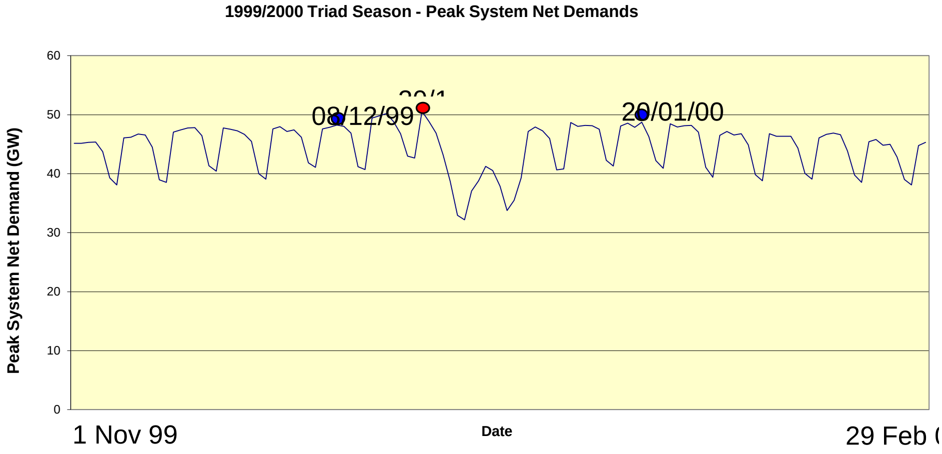


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = ($HHD_A$ - $HHD_F$) x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = ($HHEE_A$ – $HHEE_F$) x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

$= \frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

$= \frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 -£12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| SUPPLIER | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| POWER STATION WITH A BILATERAL CONNECTION AGREEMENT | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 ⋯ Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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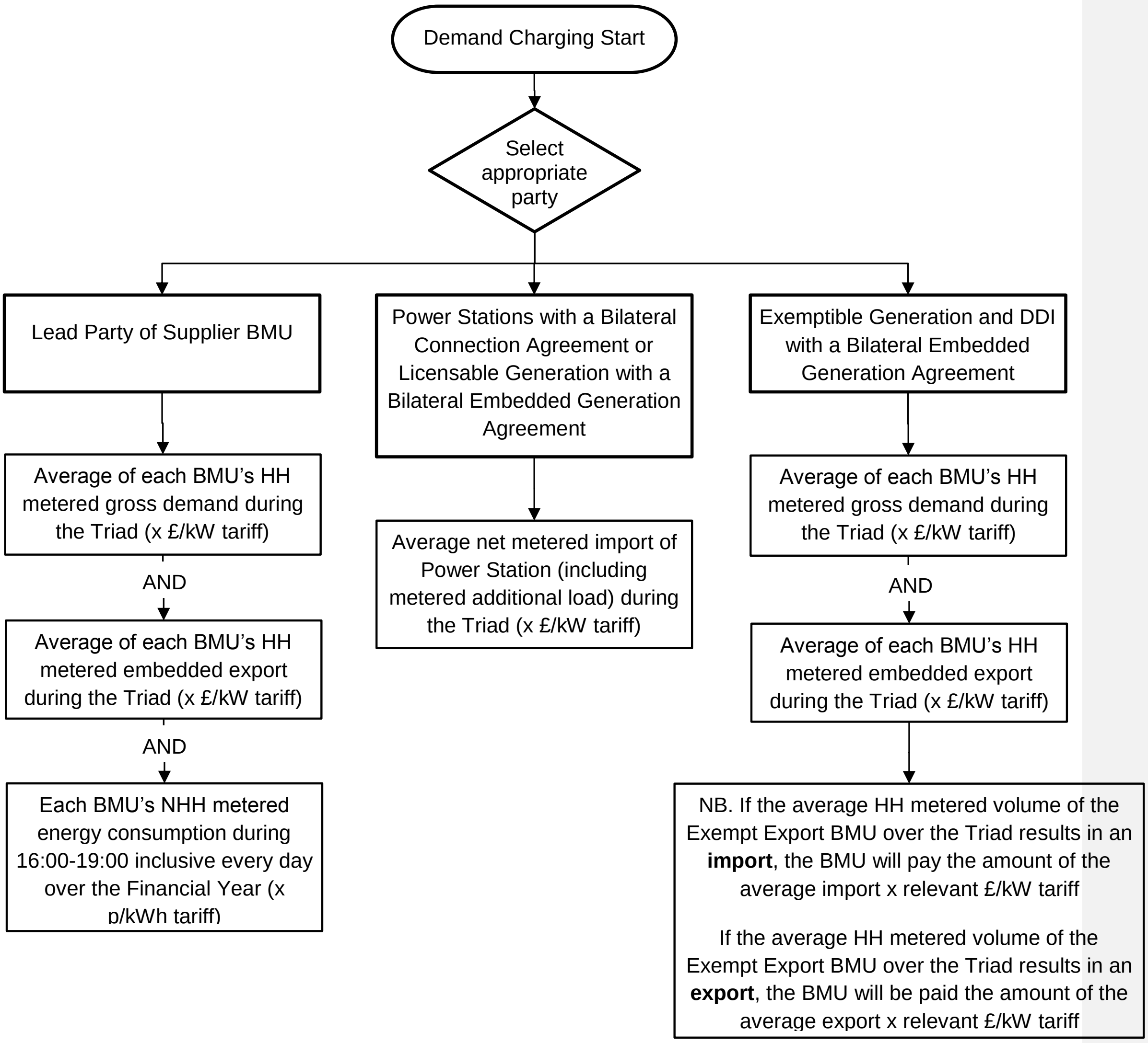
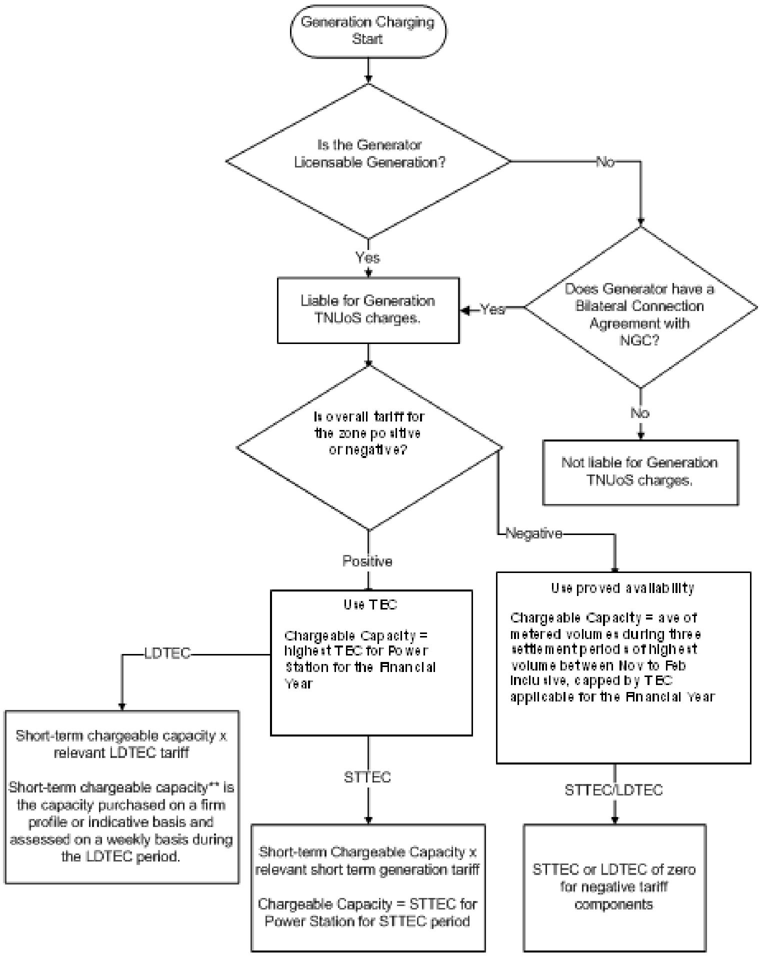



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

## Generation Charges




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

where:

T = 10,000 kW (period November 2003 to February 2004)

D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

P = 12,000 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

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D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM11

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| **Generation Plant Type** | **Peak Security Background** | **Year Round Background** |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator’s local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| Ref | Description of works | Adjustments |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

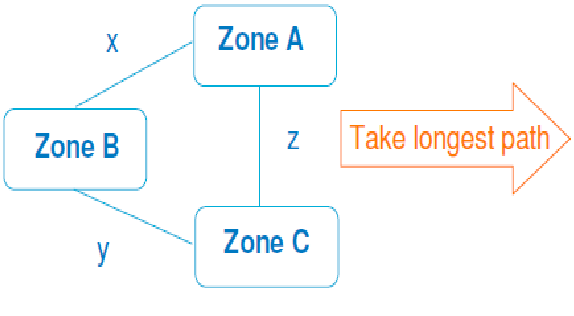
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

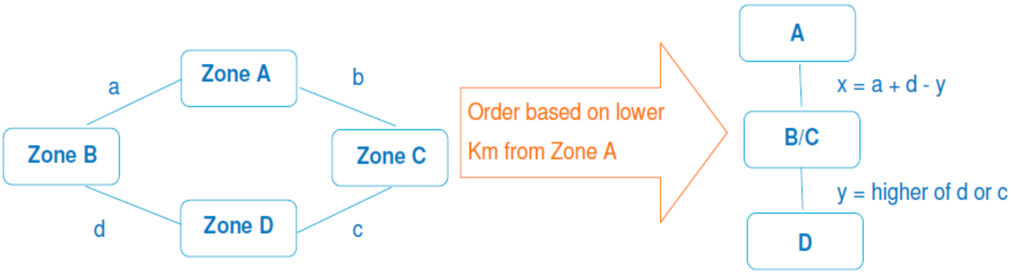
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

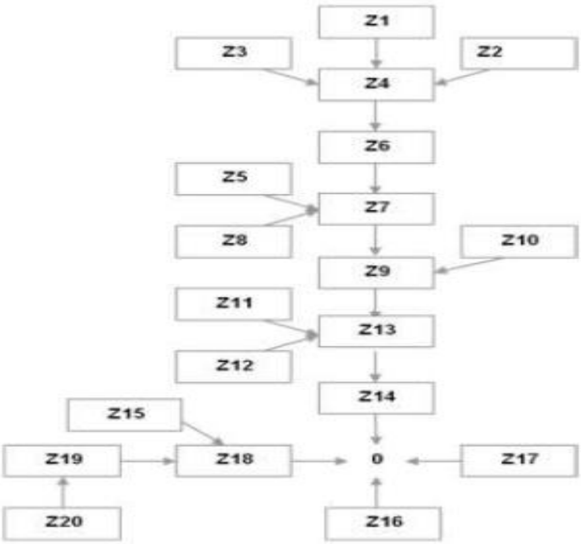
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab}\ x\ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\text{IRevOFTO} \times \text{NetworkExportCapacity}}{\text{CRevOFTO} \times \sum_{k} \text{Gen}_{k}} + LocalSF_{\text{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less embedded exports for all GSP groups .

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS

flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariff**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS.

14.15.114 The embedded export tariff will be applied to the metered Triad volumes of Embedded Exports for each demand zone as follows:

$$EET_{Di} = ITT_{DiPS} + ITT_{DiYR} + EX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
EX =

$$AEX11 = \frac{(p \times TRR) - OC - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14}(D_{Di} + EEV_{Di})}$$

Where
AGX11= Residual Tariff for embedded Affected Embedded Exports
P = Proportion of revenue to be recovered from demand
OC = Offshore Costs paid by demand
$ITRR_{DPS}$ = Peak Security Initial Transport Revenue Recovery for demand
$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for demand
$D_{Di}$ = Total forecast Metered Triad Gross Demand for each demand zone $EEV_{Di}$
= Forecast Embedded Export metered volume at Triad (MW)

The Value of $EET_{Di}$ will be floored at zero, so that $EET_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.115 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

Deleted: 113

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.116 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

Deleted: 114

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.117 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

Deleted: 115

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.118 The initial revenue recovery for Embedded Exports is the Embedded Export Tariff multiplied by the total forecast volume of Embedded Export at triad:

$$ITRR_{EE} = \sum_{Di=1}^{14}(EET_{Di} \times EEV_{Di})$$

Where

$ITTR_{EE}$ = Initial Revenue impact for Embedded Exports

$EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.119 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.120 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.121 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.122 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.123 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.124 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.125 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.126 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{G} = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_{j}$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.127 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.128 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.129 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.130 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.131 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.132 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.133 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under |

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.134 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EE}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_D = \frac{(p \times TRR) - I}{}$$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

### Final £/kW Tariff

14.15.136 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEi} = \frac{EET_{Di}}{1000}$$

Where
$ET_{EEi}$ = Effective Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.137 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEi}$$

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14.15.138 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}}$$

$$FT_{EEi} = \frac{12 \times (ET_{EEi} \times \sum_{Di=1}^{14} EET_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EET_{Di}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.139 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_{D}$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.140 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.141 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.142 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.143 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.144 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.145 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag

- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.146 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.147 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff} \quad \text{(£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

### Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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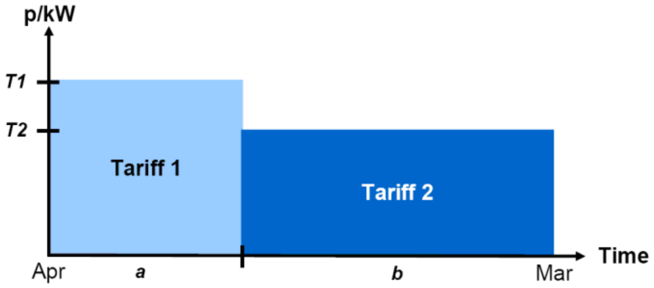
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ \ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ \ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

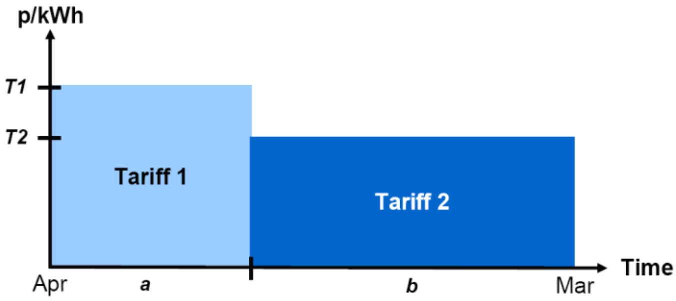
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

14.17.11 If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left( \frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12} \right)$$

Deleted: $Annual\ Liability_{D}$

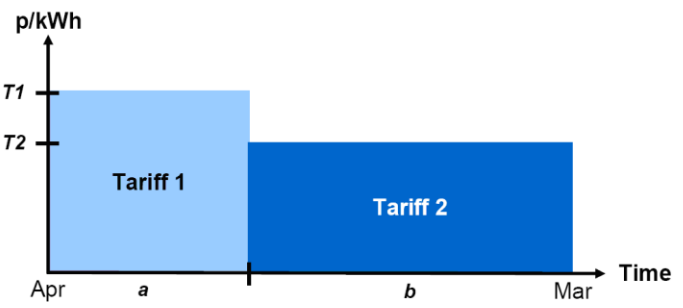
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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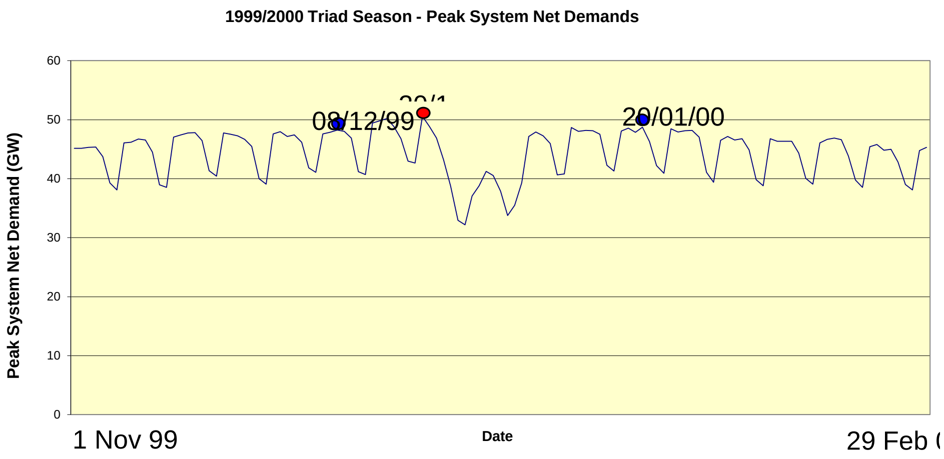


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

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14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

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**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.30. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \mathbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

**Deleted:** $\frac{£779m - £130m}{50000MW} =$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A - HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW = £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW = -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} - 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$ = -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.18.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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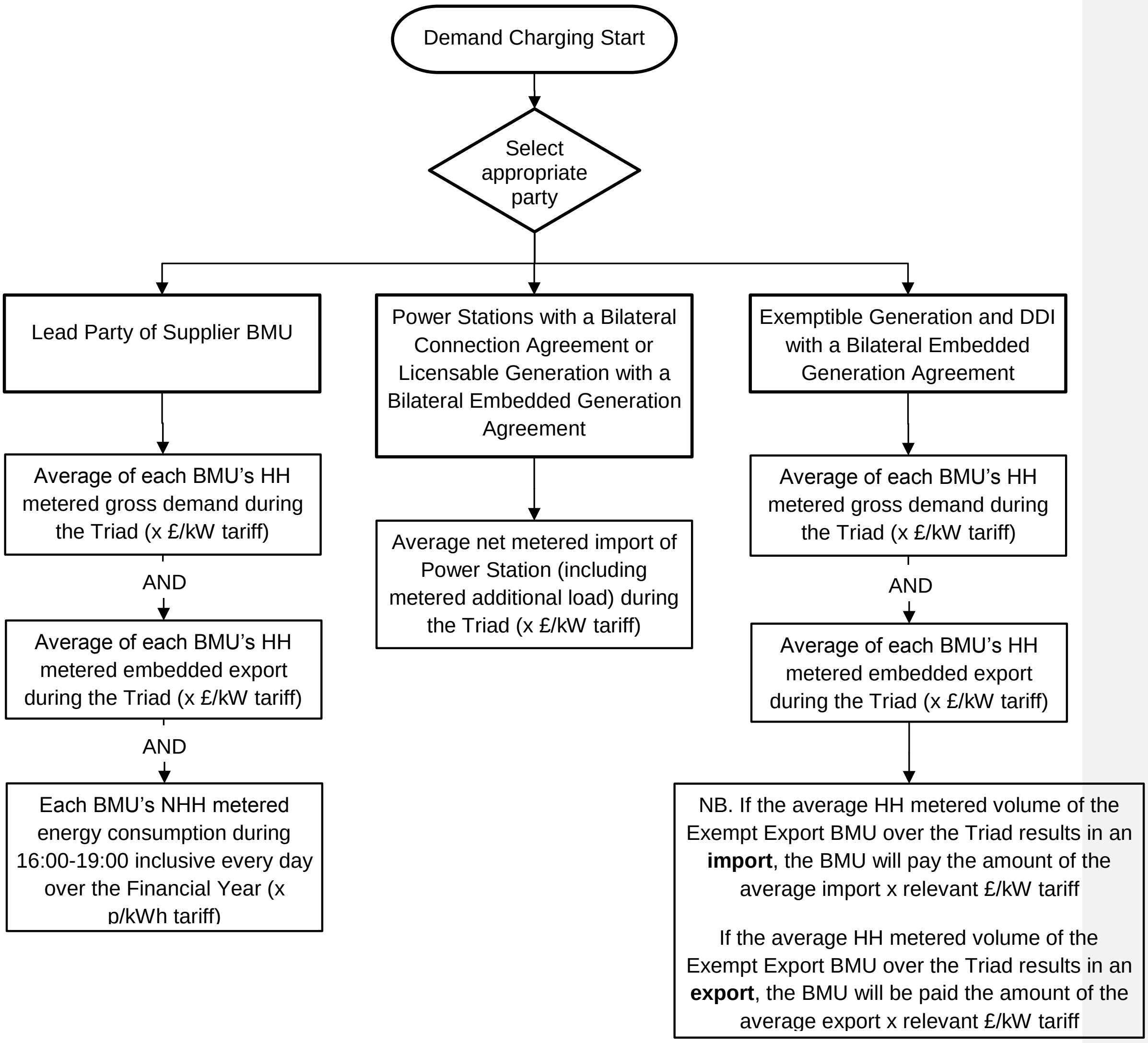
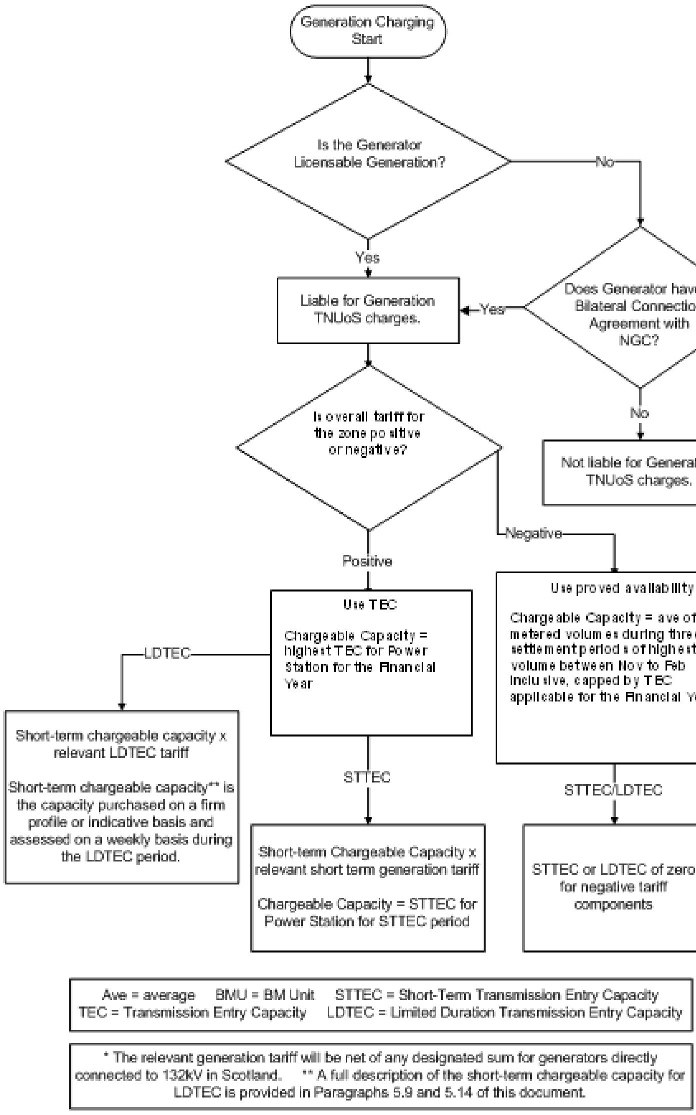



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
No
Liable for Generation TNUoS charges.
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Positive
Negative
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| Ref | Description of works | Adjustments |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{j\,YR} = \frac{NMkm_{j\,YR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

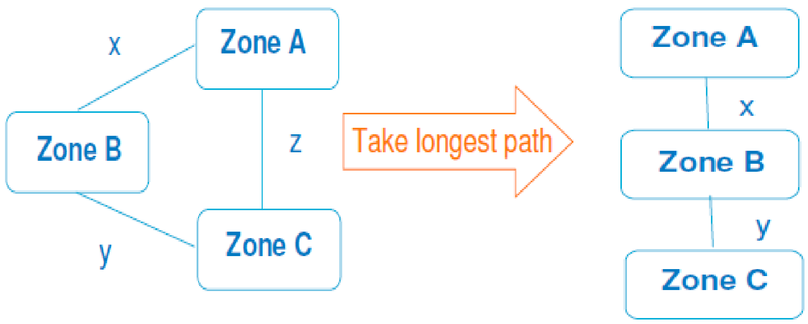
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

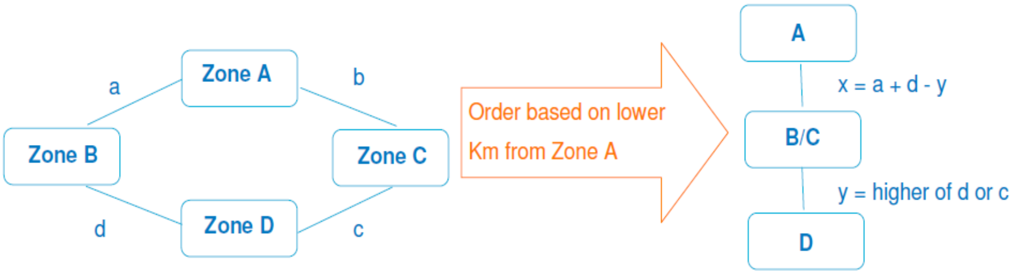
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

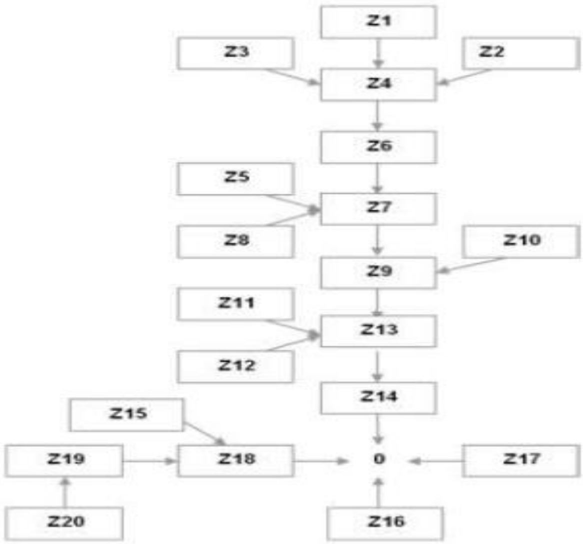
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuity factor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and

ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = $RT_G \times -1$

Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'
  - Having more than one delivery year
  - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied

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by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}\left(EETA_{Di}\times EEVA_{Di}\right)$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_{k}$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_G = \sum_{j=Gi} \mathrm{LT}_{Gi} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

| | | |
|---|---|---|
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where
$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW
$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEAi}$$
$$FT_{EEGi} = ET_{EEGi}$$

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14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.
- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Deleted: $Annual\ Liability_{D}$

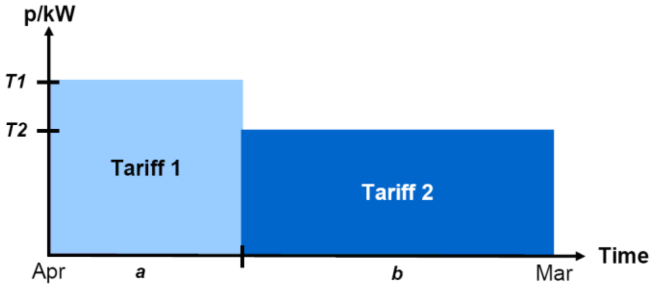
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

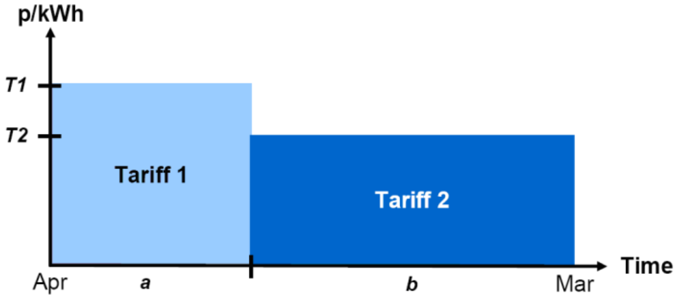
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \underline{\frac{Chargeable\ Embedded}{Export\ Capacity}} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

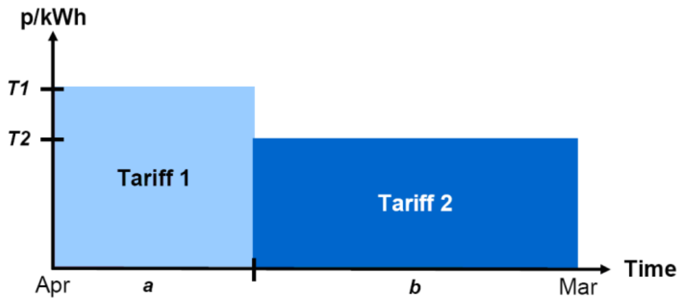
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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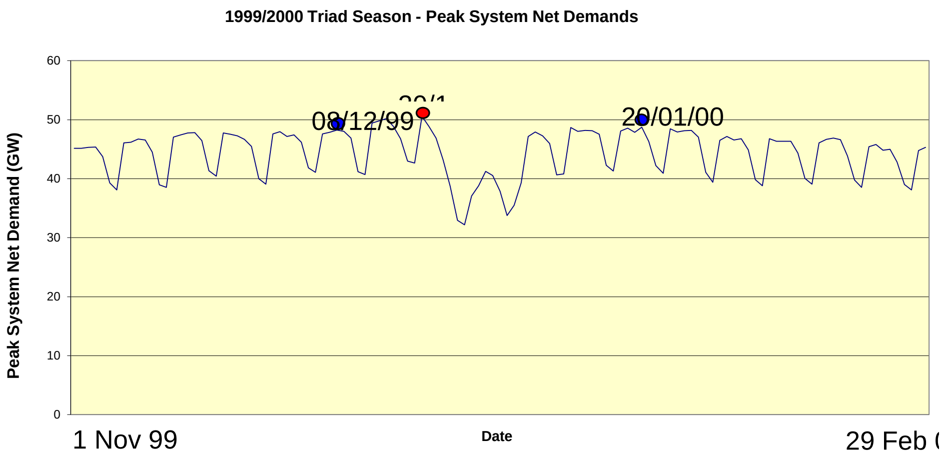


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

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- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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¶
£779m - £140m - -£10m =
£12.98/kW¶
50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17,000,000kWh - 18,000,000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1,000,000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16,700,000kWh – 17,000,000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

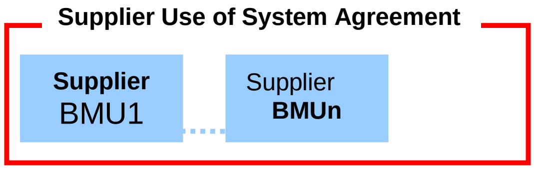
**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
|  | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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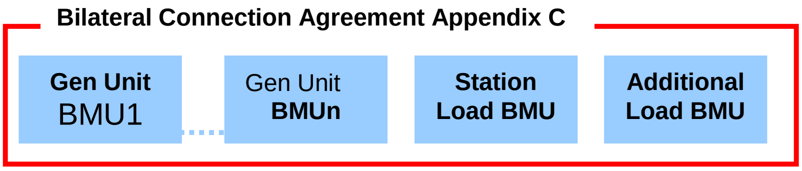
| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
|  | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| **PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT** | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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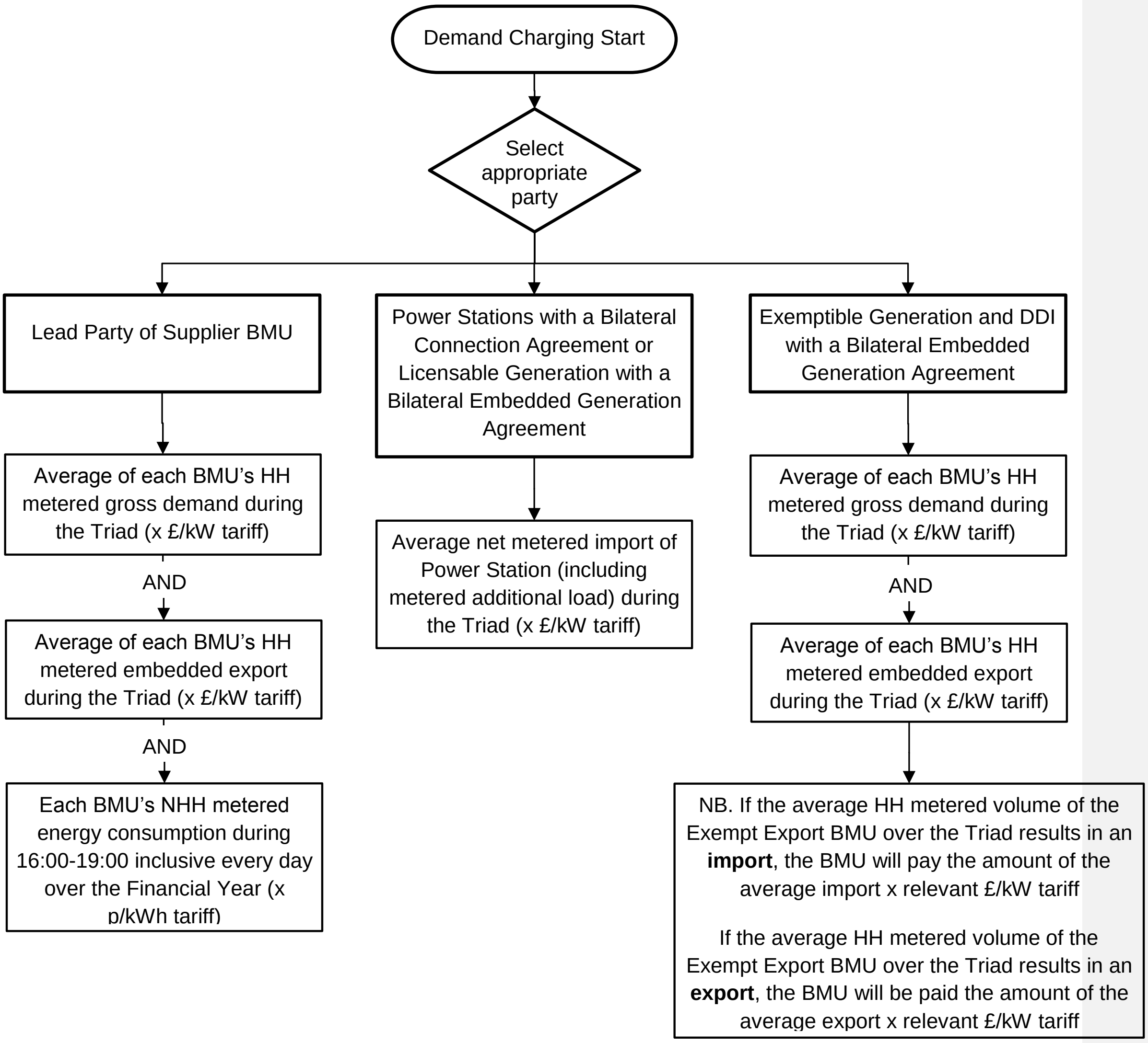
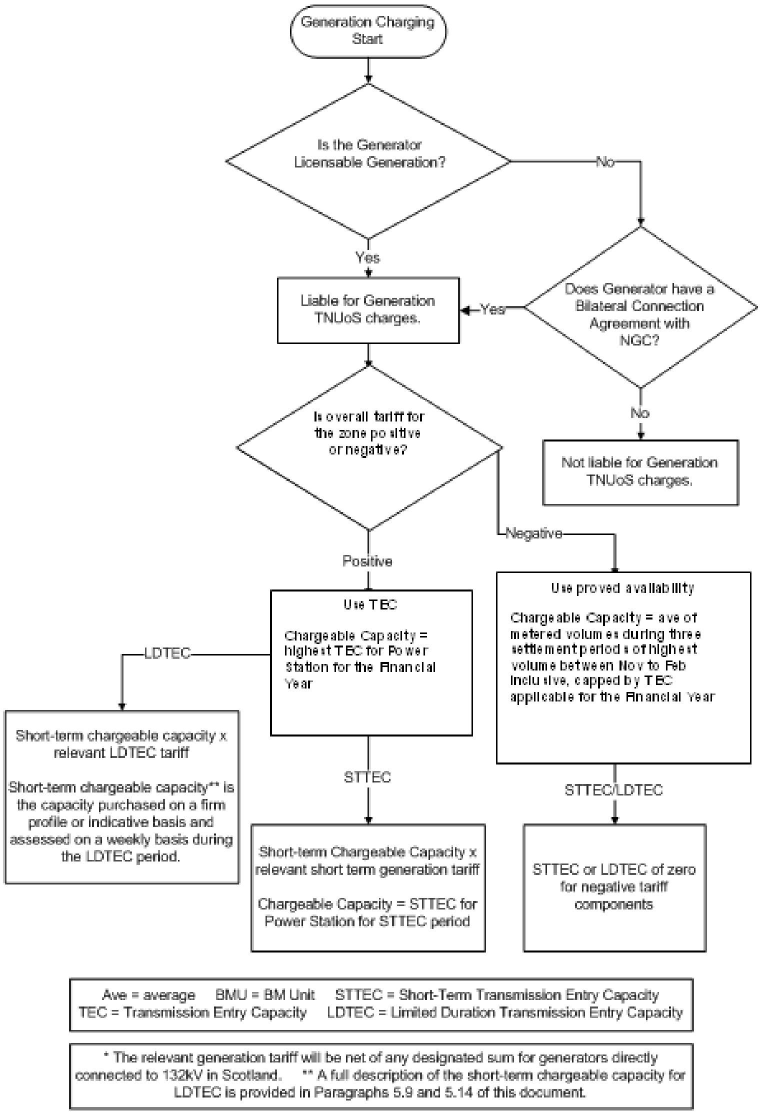



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

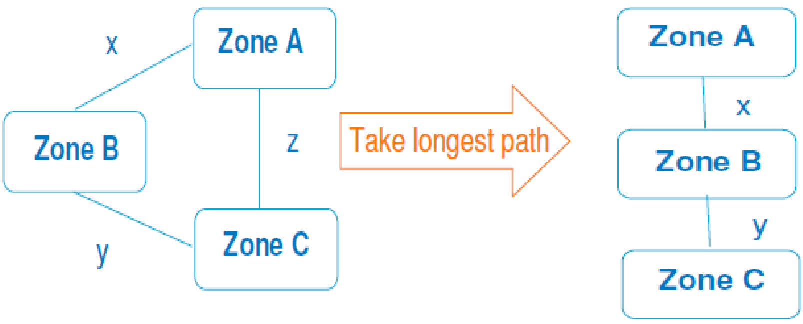
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

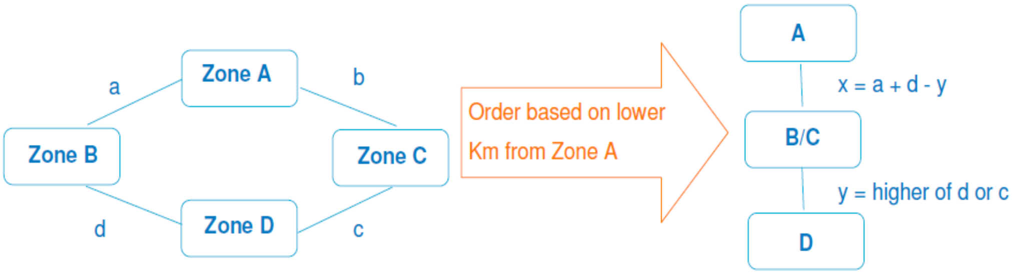
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

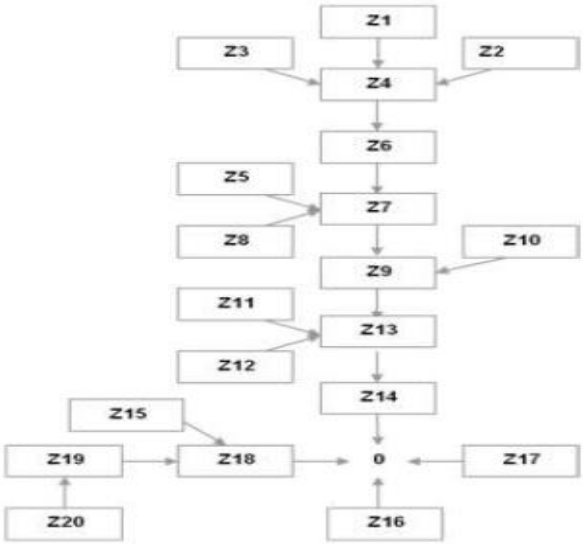
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| | |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A – ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C. The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the ‘Electricity Arbitration Association’ shall instead be to the ‘Authority’ and the Authority’s determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

$ZMkm_{DiPS}$ = Peak Security Zonal Marginal km for each demand zone

$ZMkm_{DiYR}$ = Year Round Zonal Marginal km for each demand zone

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each demand one

$ITT_{DiYR}$ = Year Round Initial Transport Tariff (£/MW) for each demand zone

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation

$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$ITRR_D$ = Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts).

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

## TNUoS Embedded Export Tariffs

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;

$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and

AEX = The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.

The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'

- Having more than one delivery year
- And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

Deleted: 113

$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}(EETA_{Di} \times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

### Deriving the Final Local Tariff (£/kW)

#### *Local Circuit Tariff*

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

Deleted: 116

$$\sum_{k} \frac{NLMkm_{Gj}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

### Onshore Local Substation Tariff

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $\mathrm{LCRR}_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.135 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

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### The Residual Tariff

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F \text{ * £/kW Tariff - } FL_G)}{NHHC_G} \text{ *100}$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.

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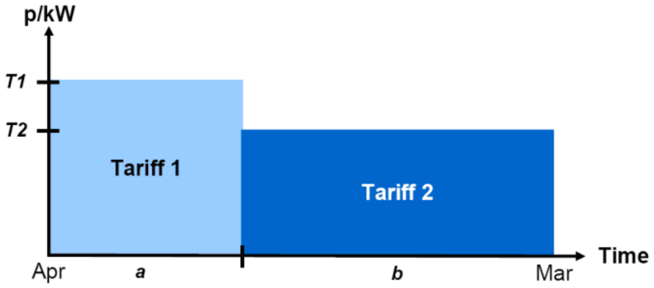



14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

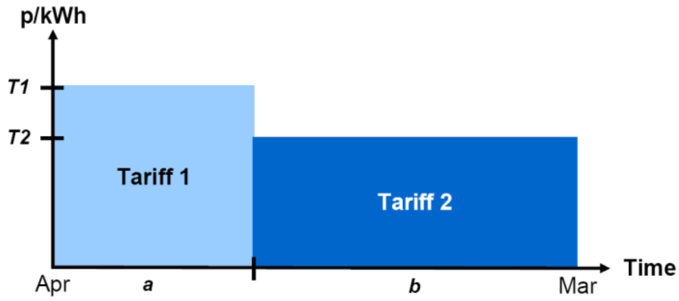
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

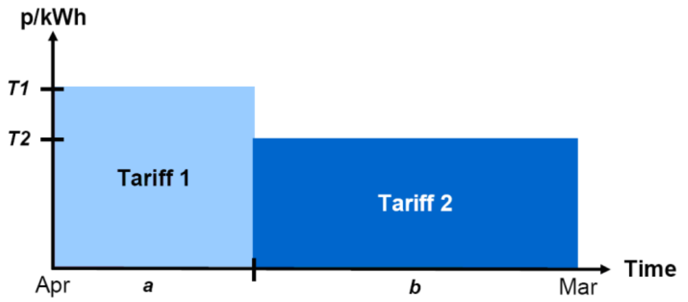
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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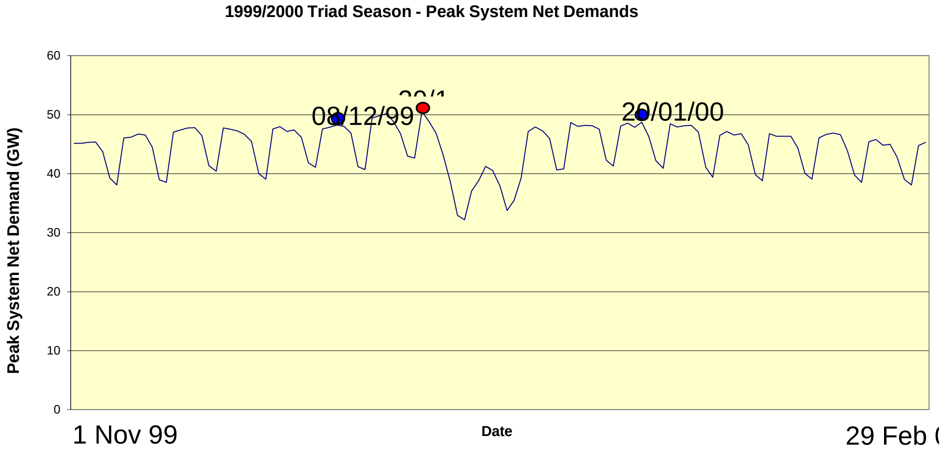


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

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**Monthly Charges**

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

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- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

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- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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¶
£779m - £140m - -£10m =
£12.98/kW¶
50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A – HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

$= \frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

$= \frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge $= \frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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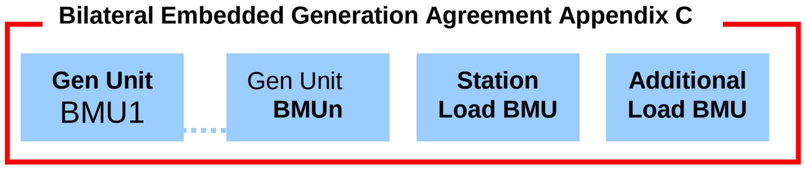
**PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.14, 14.17.15 and 14.17.18.** | See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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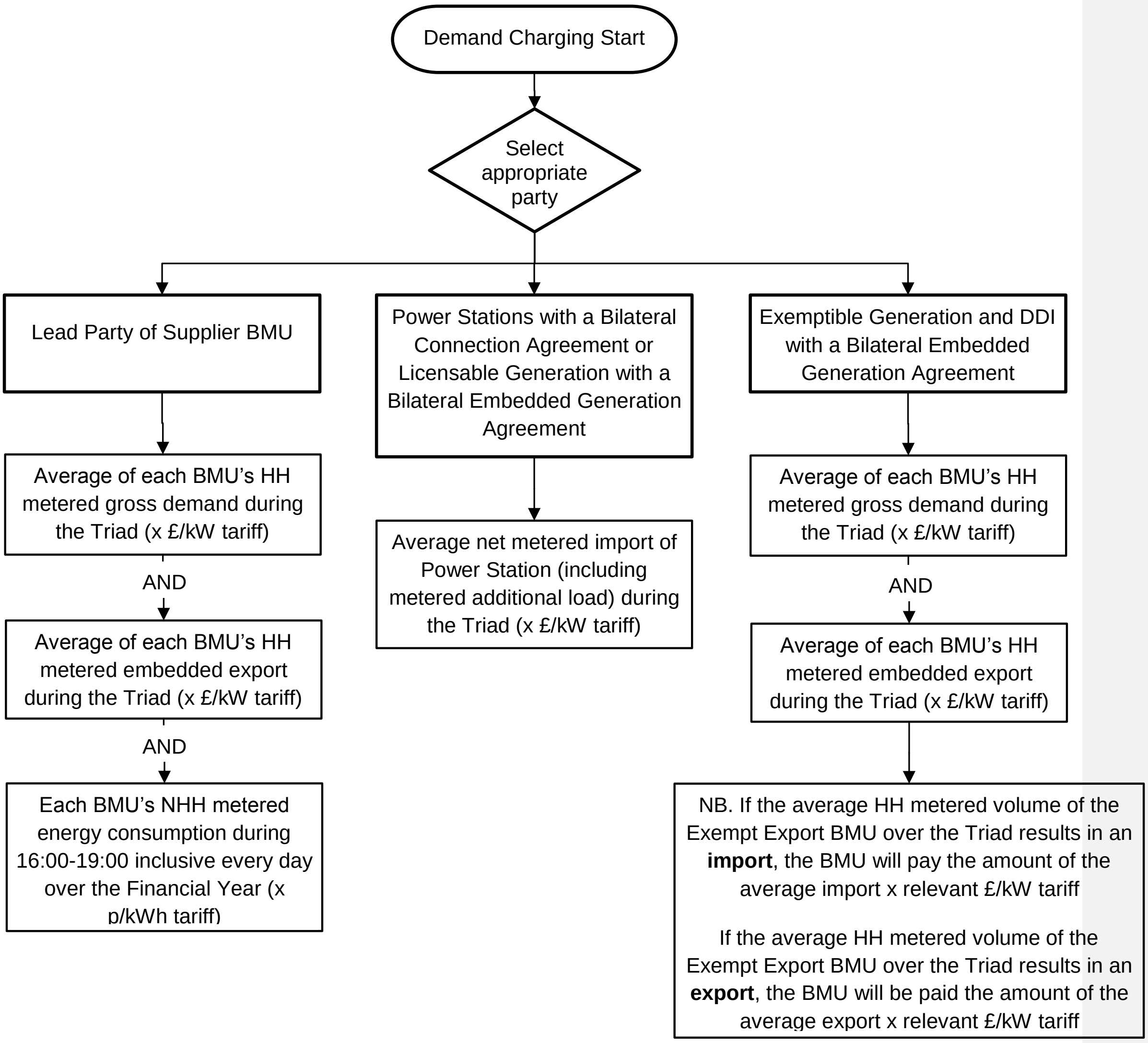
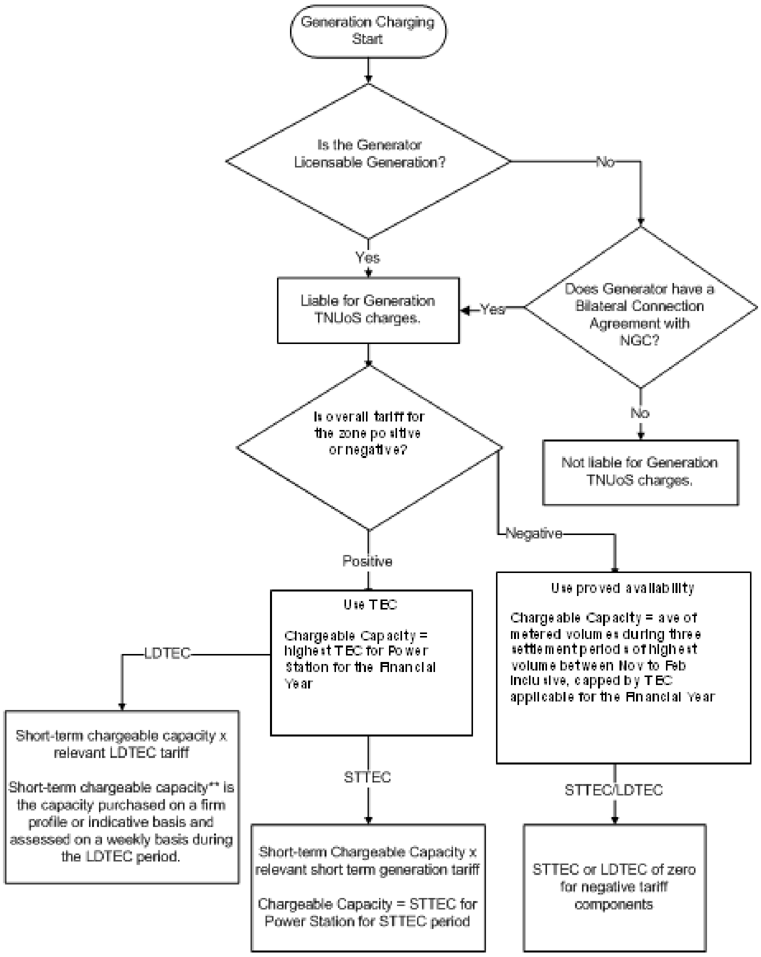



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly




Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity

* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

# CMP265 WACM14

## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

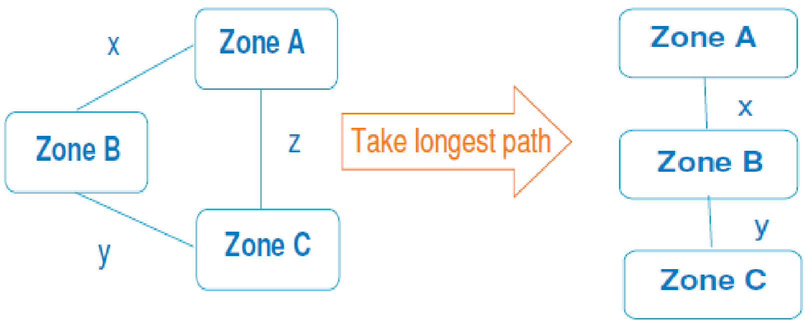
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

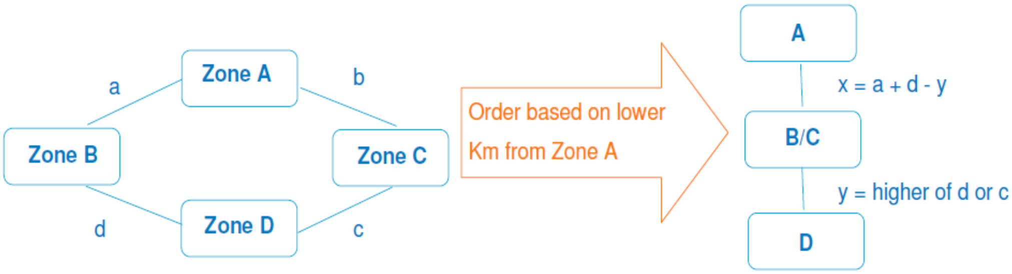
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

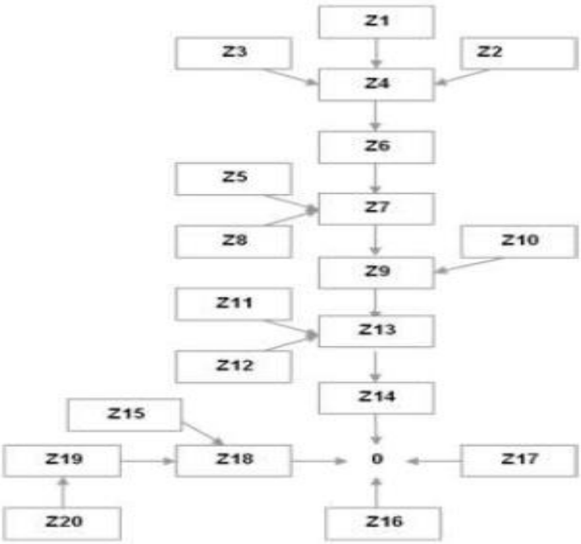
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-\left(1+WACC\right)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

<u>Scottish Hydro Region</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

<u>Scottish Power & National Grid Regions</u>

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = $(RT_G \times -1) + AGIC$

Where
$RT_G$ = Generation Residual Tariff with the inverse sign. For clarity, this means that if the Generation Residual is negative, the generation residual will be applied as a positive number for embedded exports.

AGIC= The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or

- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:

- In respect of a 'new build generating CMU'

- Having more than one delivery year

- And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand

$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}(EETA_{Di}\times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

| | | |
|---|---|---|
| $ITTR_{EEG}$ | = Initial Revenue impact for Grandfathered Embedded Exports |
| $EEVG_{Di}$ | = Forecast Grandfathered Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

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14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $\mathrm{LCRR}_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.135 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

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**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

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If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

<u>Initial 17 weeks (high rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

<u>Remaining weeks (low rate):</u>

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

**Deleted:** $Annual\ Liability_{D}$

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

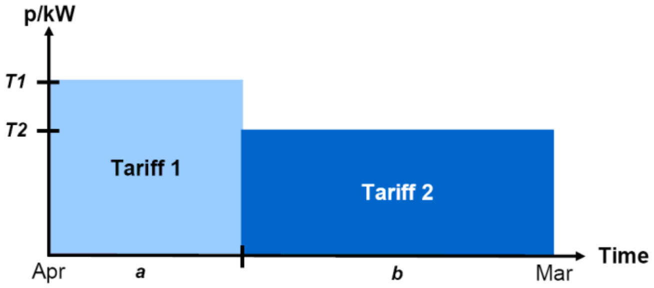
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

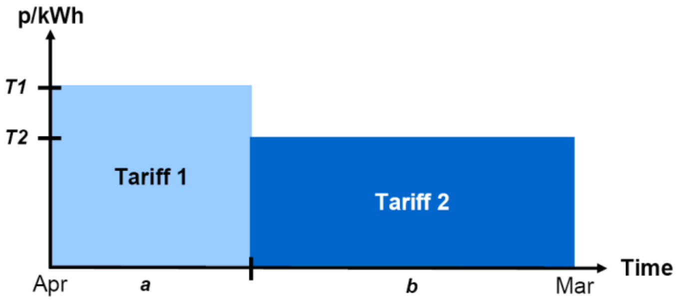
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$\textit{Annual Liability}_{Demand} = \frac{\textit{Chargeable Embedded}}{\textit{Export Capacity}} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

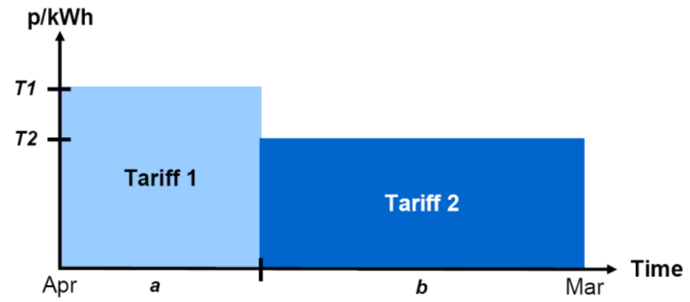
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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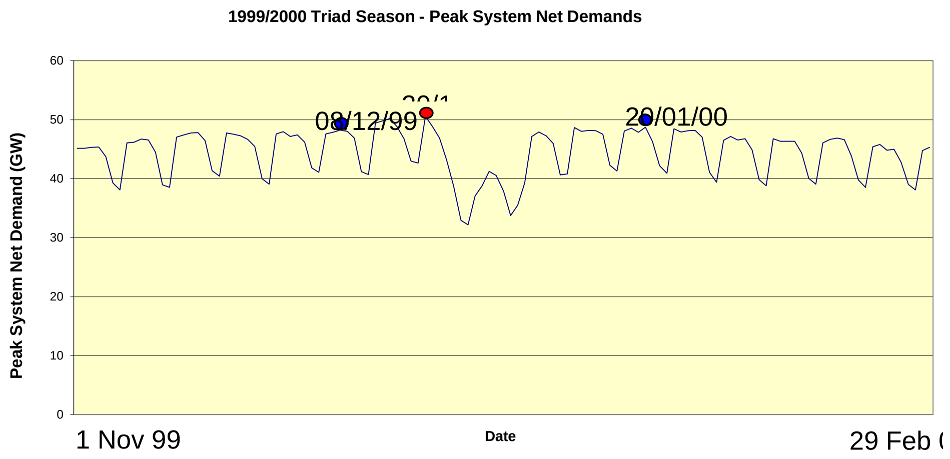


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

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14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \textbf{£3.45/kW}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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£779m - £140m - -£10m = £12.98/kW
50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A – HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

= $\frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

= $\frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** | **Station Load BMU** | **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| **PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT** | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 · Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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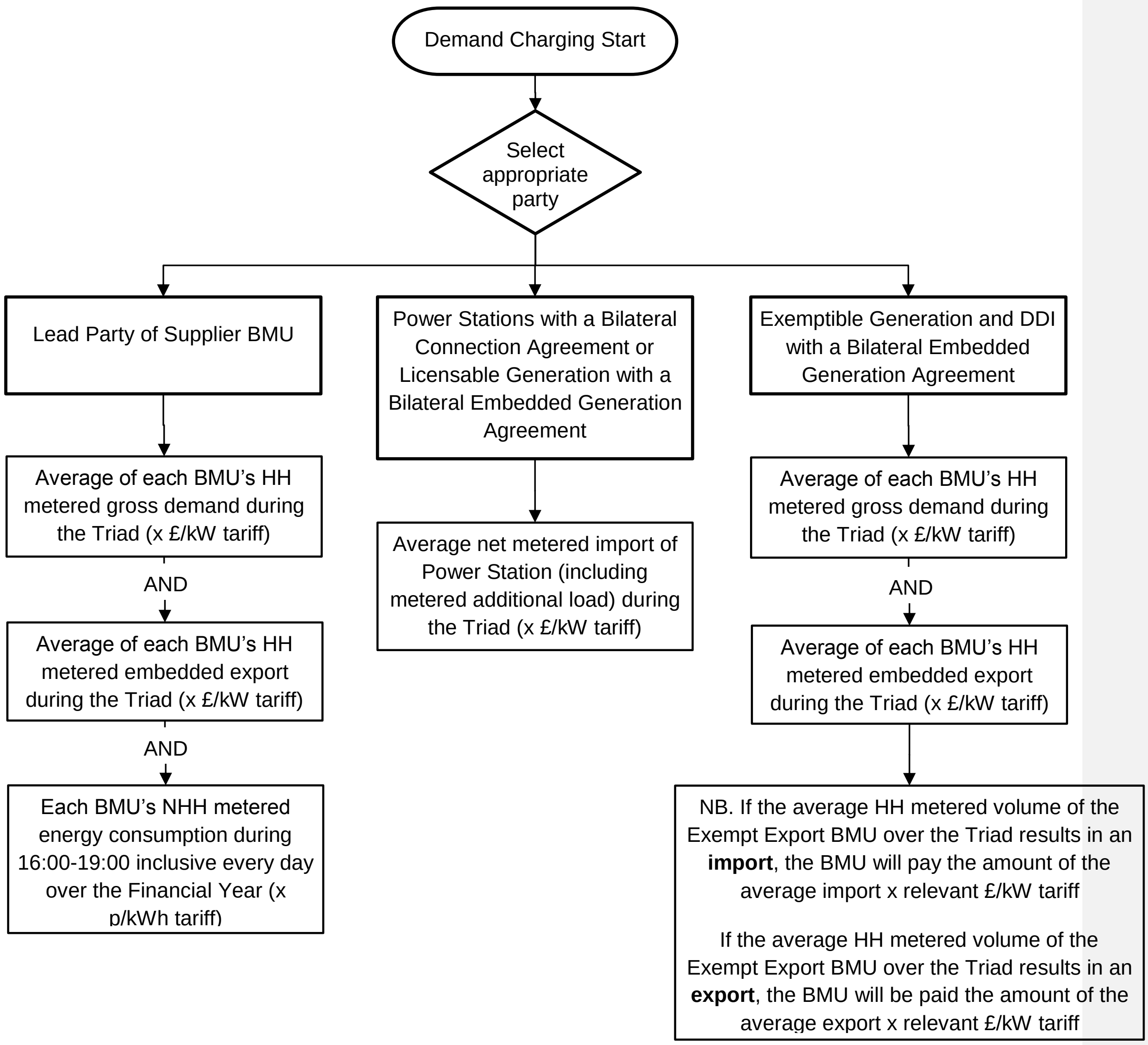
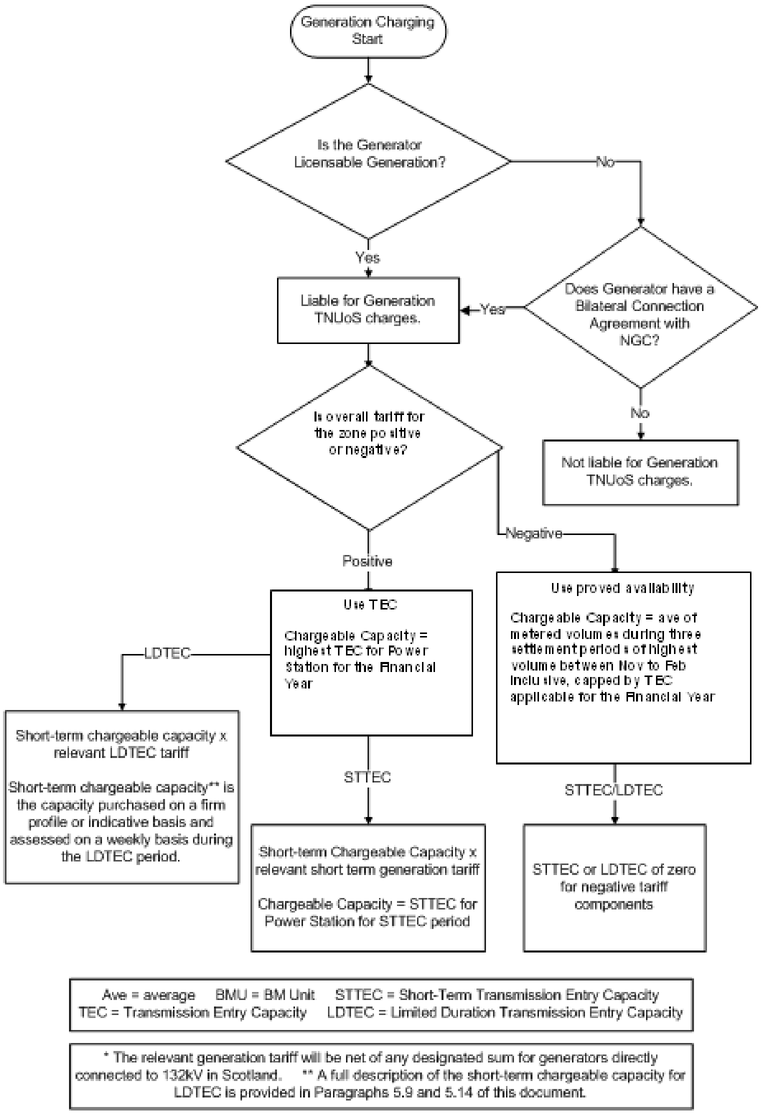



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly

Generation Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

### Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

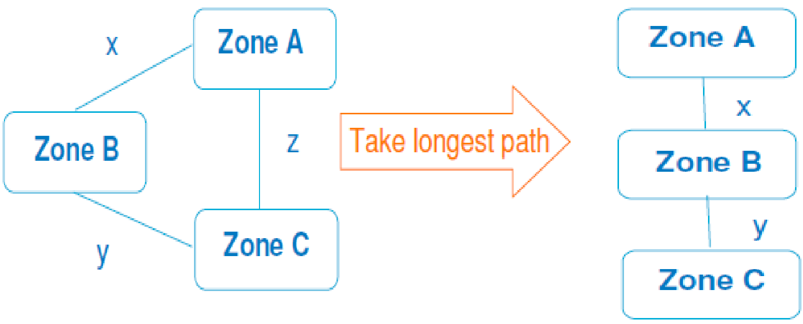
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

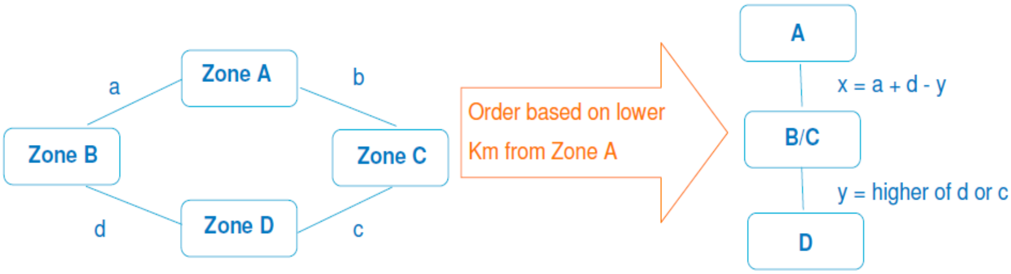
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

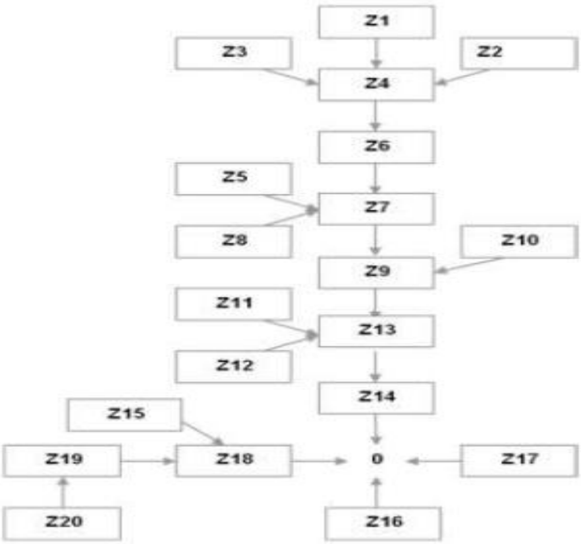
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left(-2 \times \left(\frac{LC}{LC+C}\right)\right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfactor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\, 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\, 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min\{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min(Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min\{ ILF_B \times TEC_B - RCap_{B,} \min(Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min\{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min(Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$
$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = $ABs\ (Min_{Di}(ITT_{DiPS} + ITT_{DiYR}))$

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'
  - Having more than one delivery year
  - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}(EETA_{Di}\times EEVA_{Di})$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG}=\sum_{Di=1}^{14}(EETG_{Di}\times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |

| | | | | |
|---|---|---|---|---|
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under |

recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

| | | |
|---|---|---|
| RT | = | Residual Tariff (£/MW) |
| p | = | Proportion of revenue to be recovered from demand |

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$= Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$= Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs. Deleted: 134

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability. Deleted: 135

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones: Deleted: 136

If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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# 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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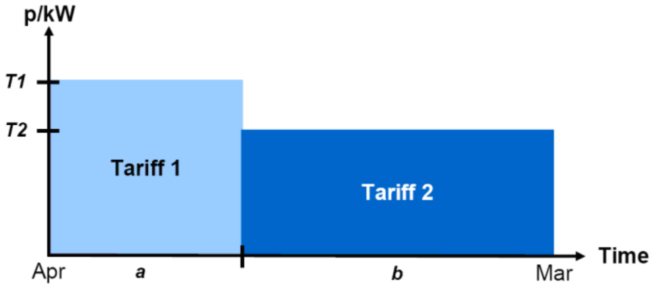
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity + Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

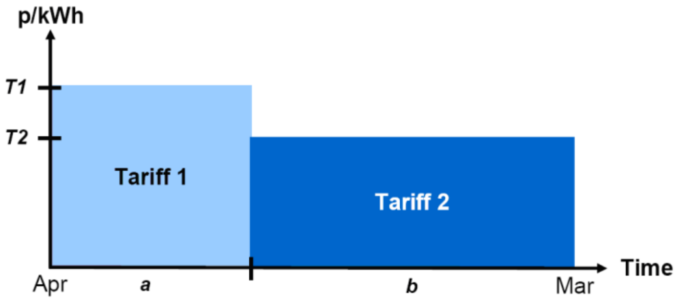
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \text{Chargeable Embedded Export Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

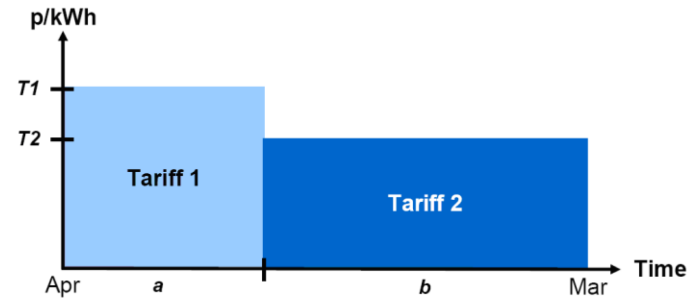
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),

- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*

- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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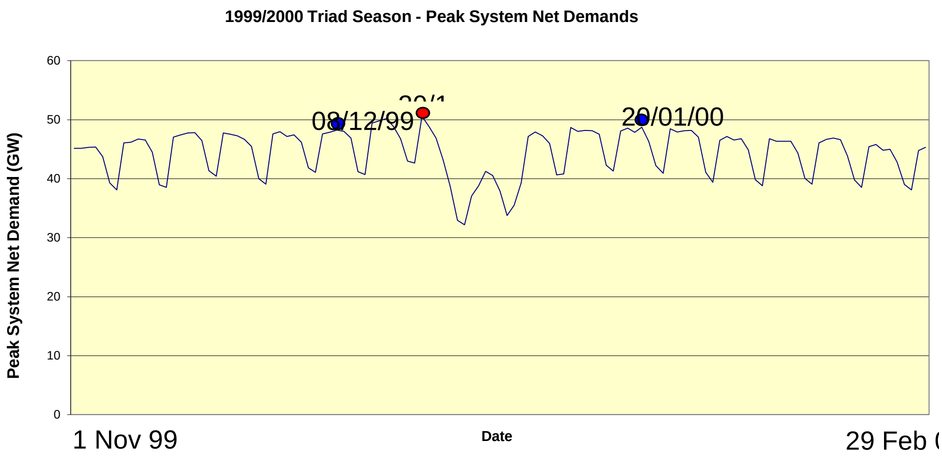


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1$^{ST}$ April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1$^{st}$ April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1$^{st}$ April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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¶
£779m - £140m - -£10m = £12.98/kW¶
50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A – HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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## Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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| PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT | |
|---|---|
| **Bilateral Embedded Generation Agreement Appendix C**<br>**Gen Unit** BMU1 … Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14, 14.17.15 and 14.17.18.** | Generation Charges<br>See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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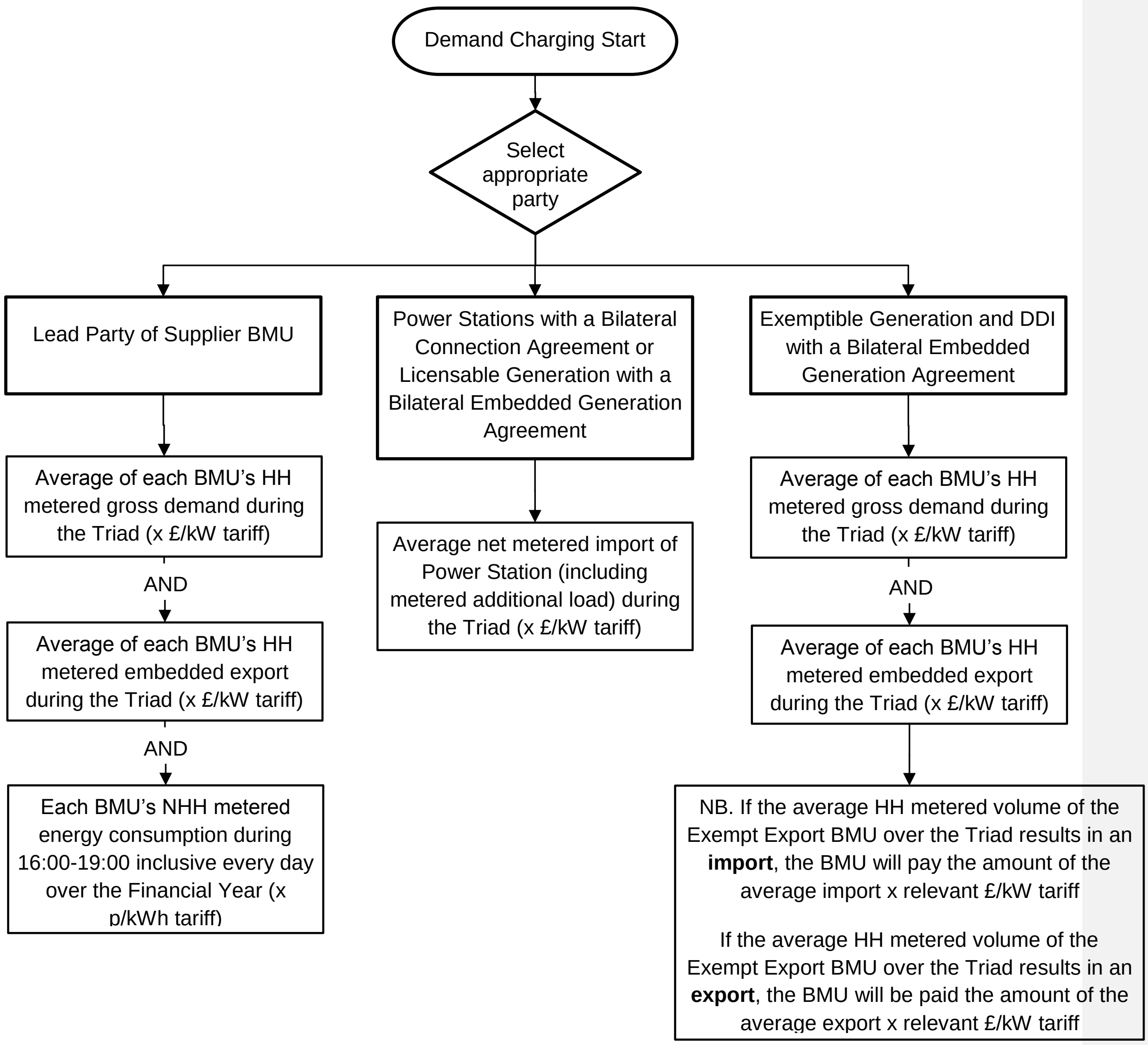
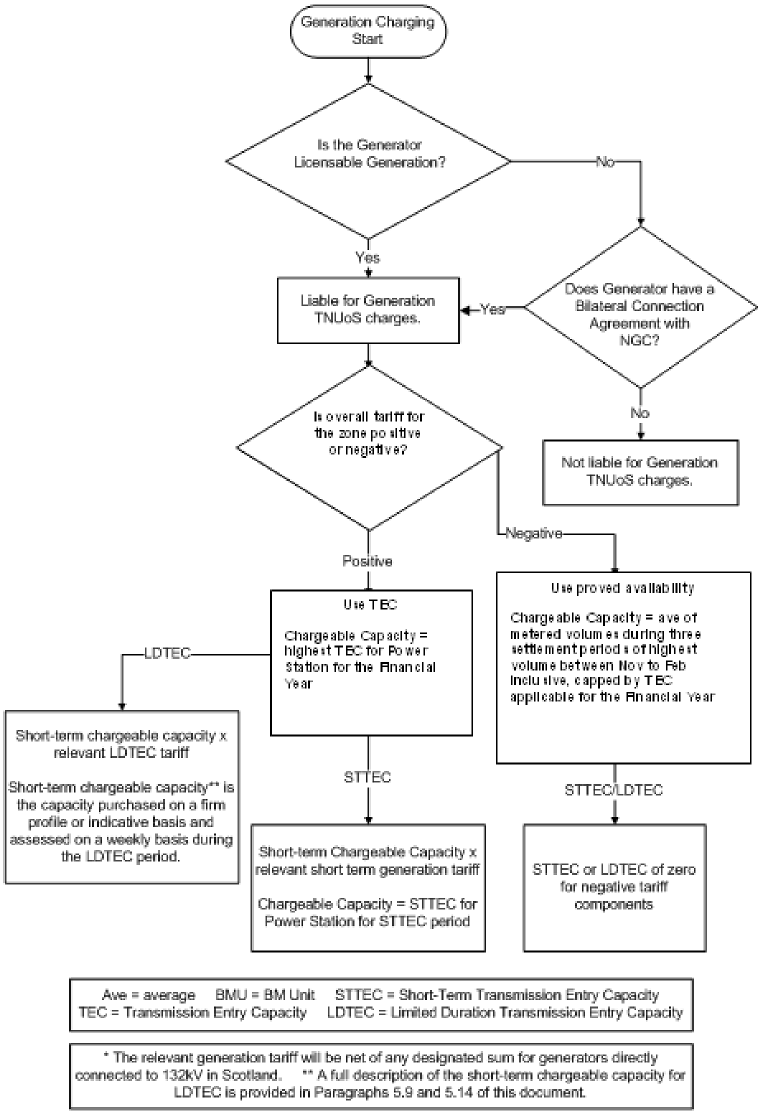



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$ = Year Round Wider nodal marginal km from transport model

$WNMkm_{YR}$ = Year Round Weighted nodal marginal km

$ZMkm_{YR}$ = Year Round Zonal Marginal km

Gen = Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di = Demand zone

Dem = Nodal Net Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

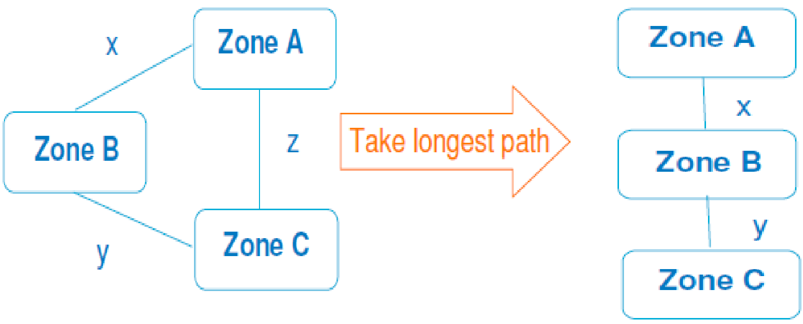
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

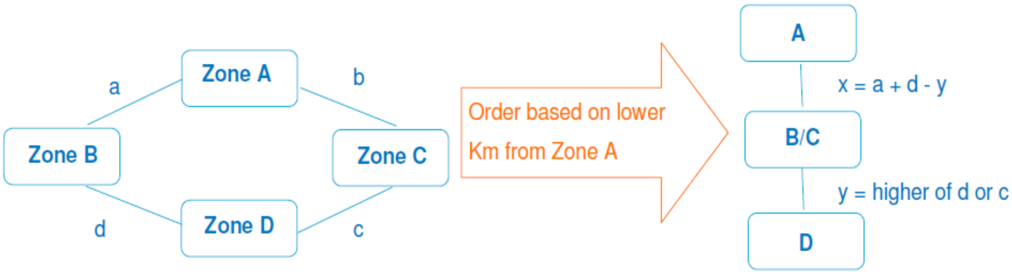
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

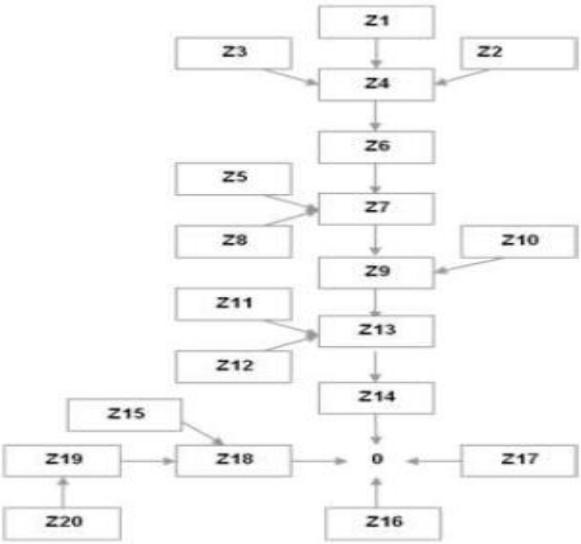
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^{L}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-\left(1+WACC\right)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period.  These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\ 400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, *CRevOFTO1* and *AvCRevOFTO* shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B

$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C

$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.

$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.

$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = AGIC + (£18.50 in April 2019 prices; indexed each year by the RPI formula set out in 14.3.6).

Where
AGIC= The Avoided GSP Infrastructure Credit (AGIC) which represents the unit cost of infrastructure reinforcement at GSPs which is avoided as a consequence of embedded generation connected to the distribution networks served by those GSPs. It is calculated from the average annuitised cost of that infrastructure reinforcement divided by the average capacity delivered by a supergrid transformer.
The Avoided GSP Infrastructure Credit is calculated at the beginning of each price control period and in the first applicable charging year following the implementation date of CMP264/265 using data submitted by onshore TSOs as part of the price control process. The data used is from the most recent [20] schemes submitted under the price control process and indexed each year by the RPI formula set out in 14.3.6 until the end of the price control. For the avoidance of doubt, this approach does not include the cost of the supergrid transformers or any other connection assets as they are paid for by the relevant DNOs thorough their connection charges.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or

- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'
  - Having more than one delivery year
  - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

| | | |
|---|---|---|
| $ITRR_{GPS}$ | = | Peak Security Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $F_{PS}$ | = | Peak Security flag appropriate to that generator type |
| n | = | Number of generation zones |

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

| | | |
|---|---|---|
| ITRRDPS | = | Peak Security Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts) |

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR} \times D_{Di}\right) = ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA} = \sum_{Di=1}^{14}\left(EETA_{Di} \times EEVA_{Di}\right)$$

Where

| | | |
|---|---|---|
| $ITTR_{EEA}$ | = | Initial Revenue impact for Affected Embedded Exports |
| $EEVA_{Di}$ | = | Forecast Affected Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14} (EETG_{Di} \times EEVG_{Di})$$

Where

$ITTR_{EEG}$ = Initial Revenue impact for Grandfathered Embedded Exports

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_k \frac{NLMkm_{Gj}{}^L \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^L$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where

| | | |
|---|---|---|
| $LCRR_G$ | = | Local Charge Revenue Recovery |
| $G_j$ | = | Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users) |

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

14.15.135 The revenue from the offshore substation local tariff is calculated by:

$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

$TRR_t$ = TNUoS Revenue Recovery target for year t

$R_t$ = Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence.

$PVC_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

$SG_{t-1}$ = The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z} (FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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## Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F \text{ * £/kW Tariff} - FL_G)}{NHHC_G} \text{ *100}$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

### Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

### Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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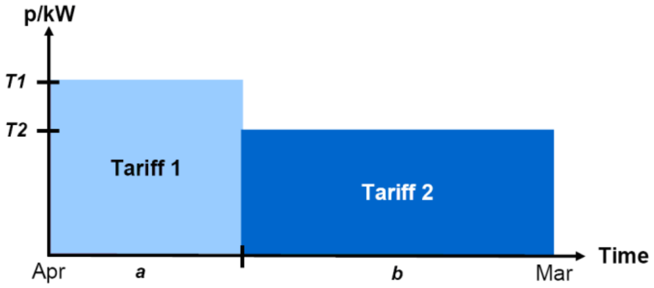
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

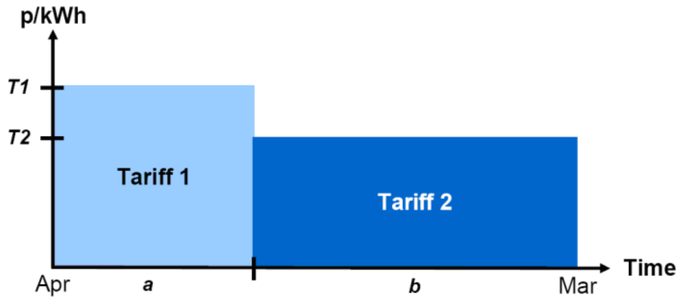
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




**Basis of Embedded Export Charges**

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

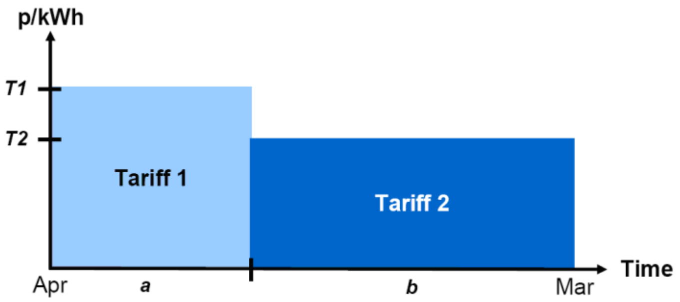
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

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14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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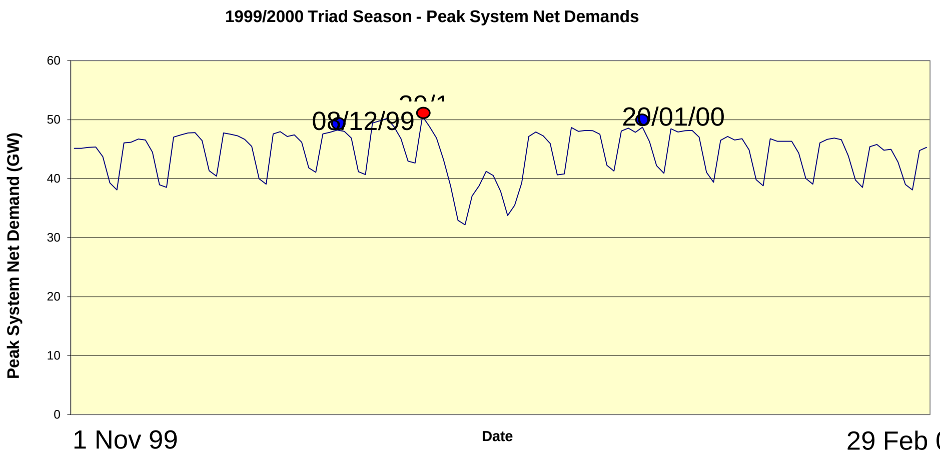


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

14.17.32 A manifest error shall be defined as any of the following:

a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -

190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**

1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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**Deleted:** $\frac{£779m - £130m}{50000MW} =$

¶

£779m - £140m - -£10m = £12.98/kW¶

50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A - HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times \text{p/kWh Tariff}}{100}$

$= \frac{(17{,}000{,}000\text{kWh} - 18{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$

$= \frac{-1{,}000{,}000\text{kWh} \times 1.20\text{p/kWh}}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000\text{kWh} – 17{,}000{,}000\text{kWh}) \times 1.20\text{p/kWh}}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

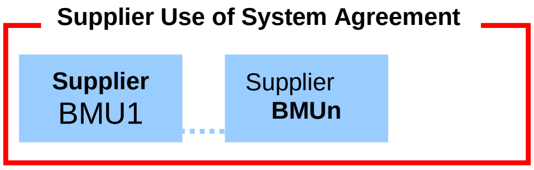
**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

**SUPPLIER**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.13 and 14.17.18.** | None. |

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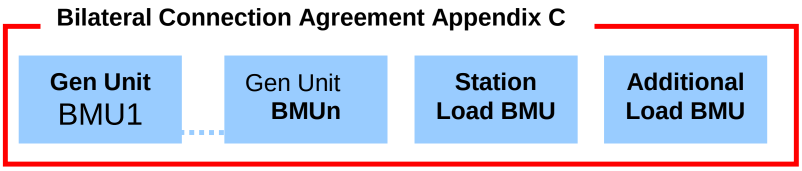
**POWER STATION WITH A BILATERAL CONNECTION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.14.** | See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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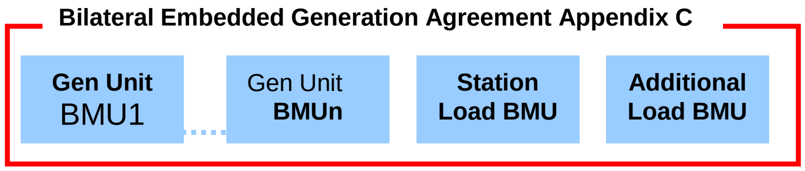
**PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT**




| Demand Charges | Generation Charges |
|---|---|
| See **14.17.14, 14.17.15 and 14.17.18.** | See **14.18.1 ii).**<br><br>For generators in positive zones, see **14.18.3 to 14.18.12 and 14.18.18.**<br><br>For generators in negative zones, see **14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.** |

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# 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

## Demand Charges

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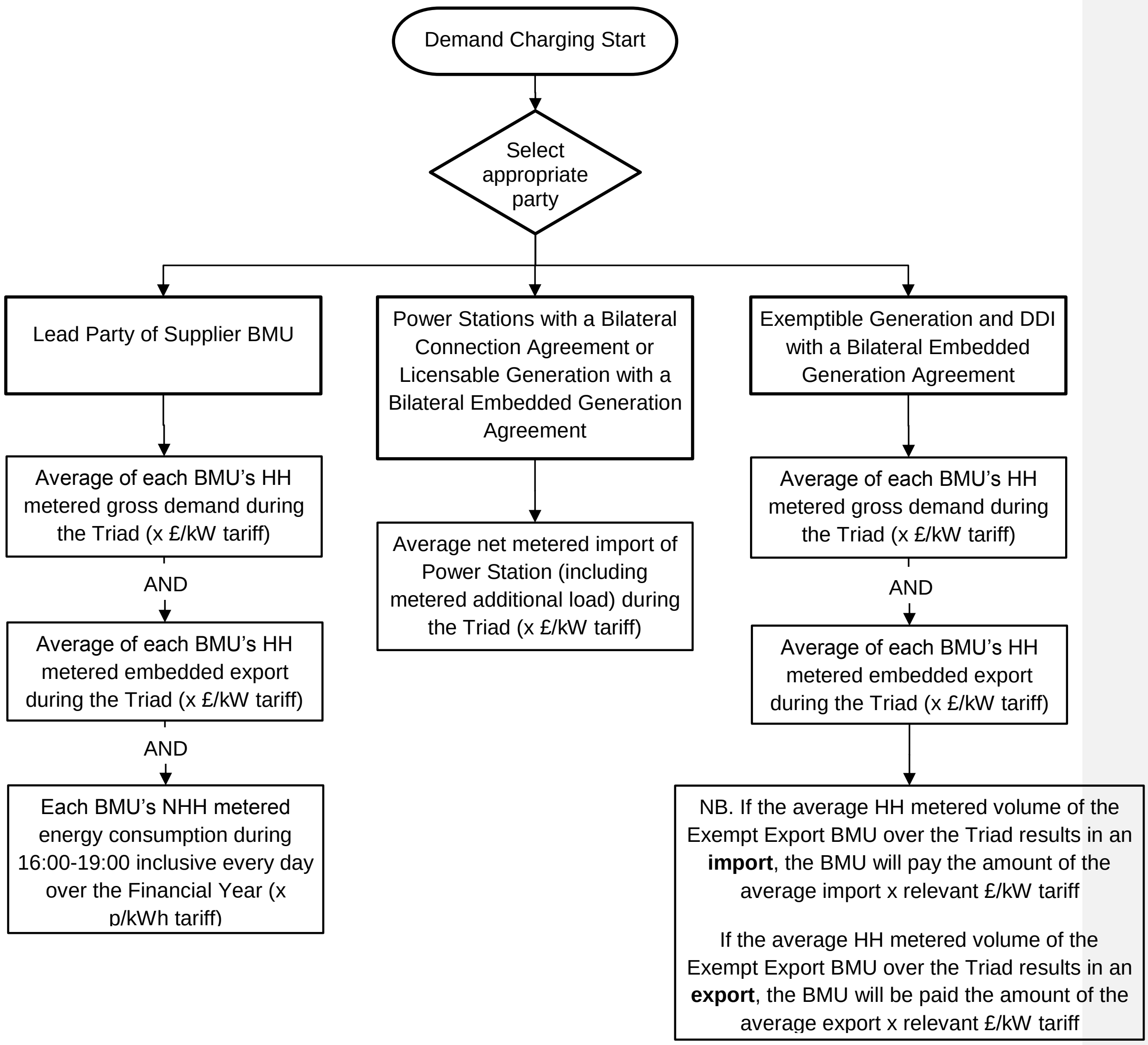
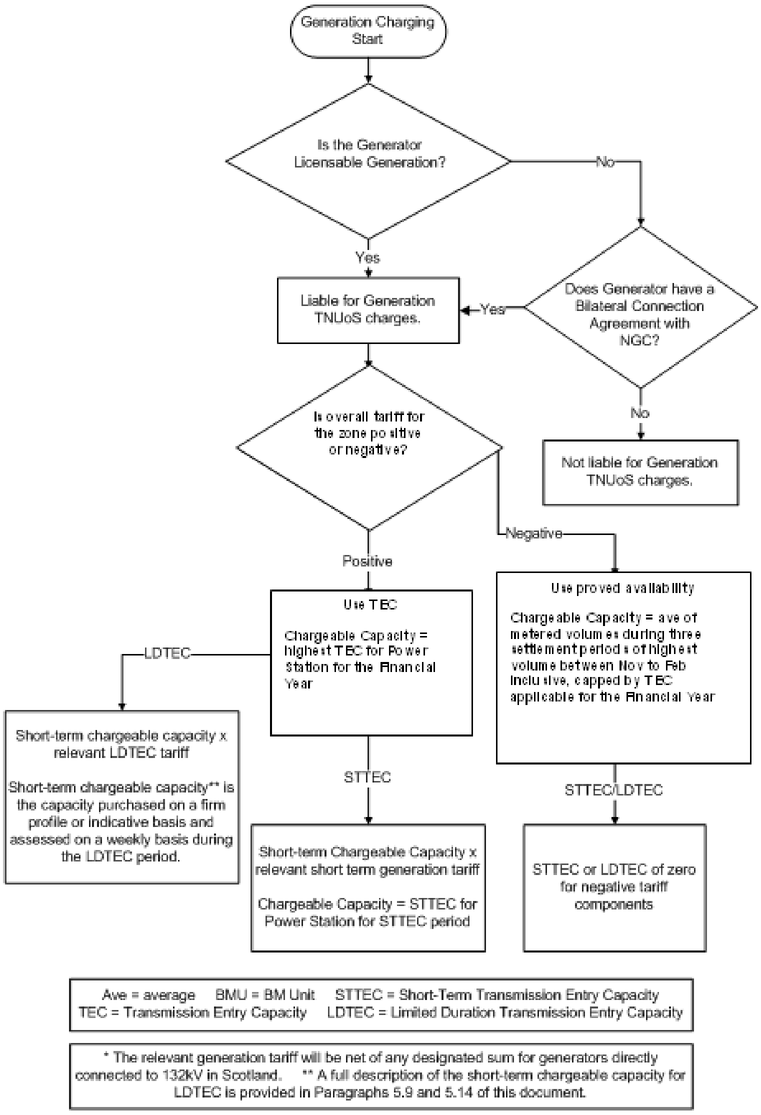



BMU = BM Unit    DDI = Derogated Distribution Interconnector
HH = Half hourly    NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

$F = T$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

$F = T * D/P$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

### iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

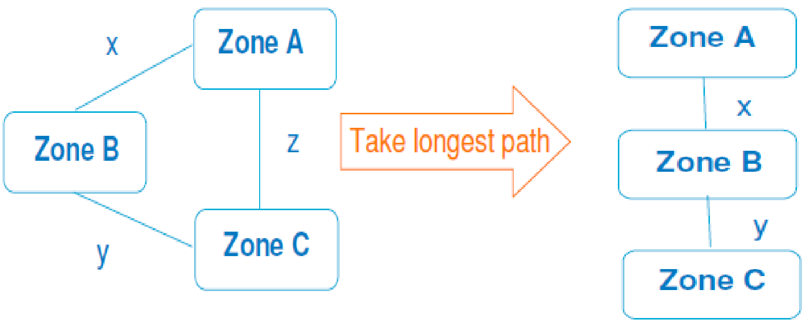
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| Carbon | Low Carbon |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

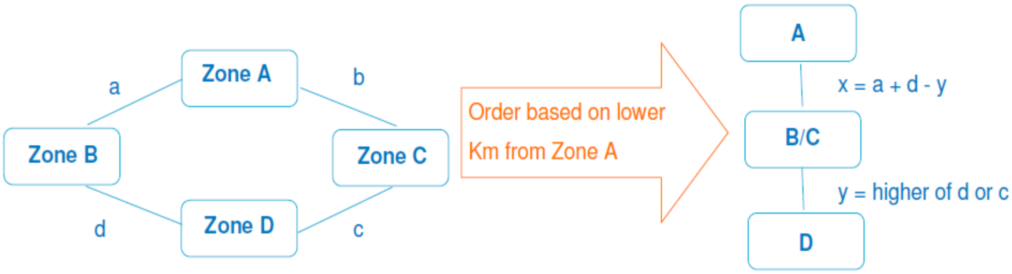
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

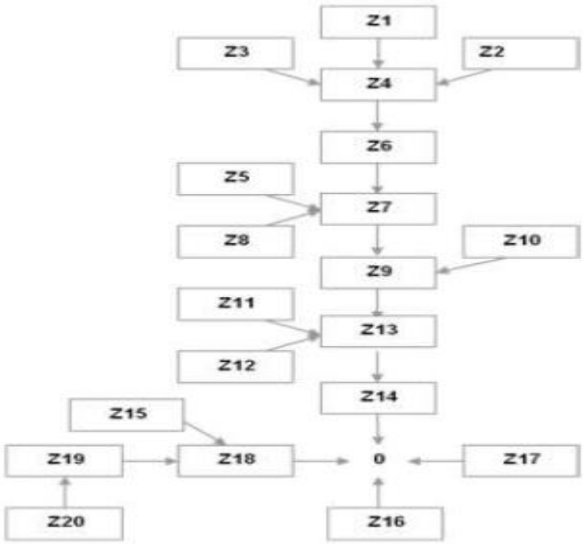
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ <u>then the BSF is calculated using the following formula: -</u>

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-\left(1+WACC\right)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.

b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.

c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.

d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

| | | |
|---|---|---|
| NetworkExportCapacity | = | the total export capacity of the network disregarding any Offshore Interlinks |
| k | = | the generation connected to the offshore network |

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85

CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81

And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where

$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone

$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone

$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant

LSF = Locational Security Factor

$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone

$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone

$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ | = | Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year “t” the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX = £32.30 in April 2016 prices; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
  - In respect of a 'new build generating CMU'
  - Having more than one delivery year
  - And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

Deleted: 113

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS} \times G_{Gi}\right) = ITRR_{G\,YRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS}\times G_{Gi}\times ALF\right)=ITRR_{G\,YRS}$$

Where:

| | | |
|---|---|---|
| $ITRR_{GYRNS}$ | = | Year Round Not-Shared Initial Transport Revenue Recovery for generation |
| $ITRR_{GYRS}$ | = | Year Round Shared Initial Transport Revenue Recovery for generation |
| ALF | = | Annual Load Factor appropriate to that generator. |

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

| | | |
|---|---|---|
| $ITRR_{DYR}$ | = | Year Round Initial Transport Revenue Recovery for gross GSP group demand |

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}(EETA_{Di}\times EEVA_{Di})$$

Where

| | |
|---|---|
| $ITTR_{EEA}$ | = Initial Revenue impact for Affected Embedded Exports |
| $EEVA_{Di}$ | = Forecast Affected Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG}=\sum_{Di=1}^{14}(EETG_{Di}\times EEVG_{Di})$$

Where

| | |
|---|---|
| $ITTR_{EEG}$ | = Initial Revenue impact for Grandfathered Embedded Exports |

$EEVG_{Di}$ = Forecast Grandfathered Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

Deleted: 116

$$\sum_k \frac{NLMkm_{Gj}^{\ L} \times EC \times LocalSF_k}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| *k* | = | Local circuit *k* for generator |
| $NLMkm_{Gj}^{L}$ | = | Year Round Nodal marginal km along local circuit *k* using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit *k* |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

Deleted: 117

(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |

| | | | | |
|---|---|---|---|---|
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore

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Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |
| $PVC_t$ | = | Forecast Revenue from Pre-Vesting connection charges for year t |
| $SG_{t-1}$ | = | The proportion of the under/over recovery included within $R_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery. |

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where
$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW
$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS,}$ $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

$$FT_{Gi} = ET_{Gi}$$
$$FT_{Di} = ET_{Di}$$
$$FT_{EEAi} = ET_{EEAi}$$
$$FT_{EEGi} = ET_{EEGi}$$

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14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

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Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then *i* = 1 to z

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Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For *i*= 1 to z: $RFT_{Di} = 0$

For *i*=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where
$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)
$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

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14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones*.*

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14.15.145 New Grid Supply Points will be classified into zones on the following basis:

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- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation

- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where $FT$ is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
$P$ is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \underline{Chargeable\ Gross\ Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Deleted: $Annual\ Liability_{D}$

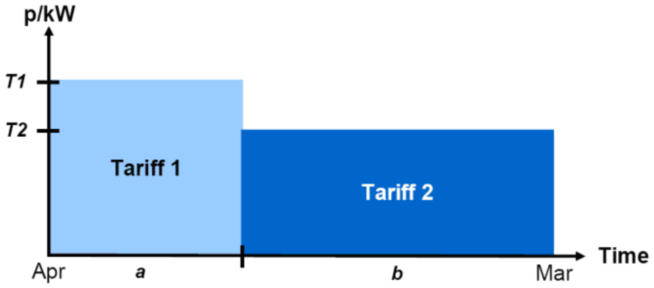
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

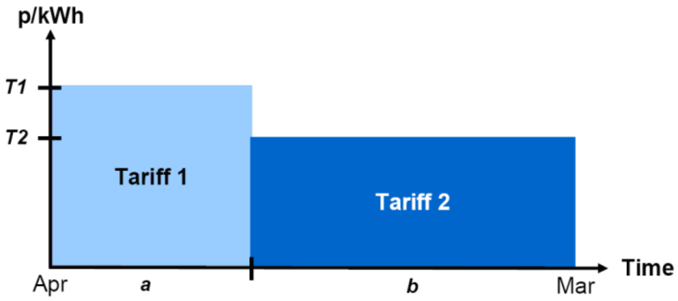
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

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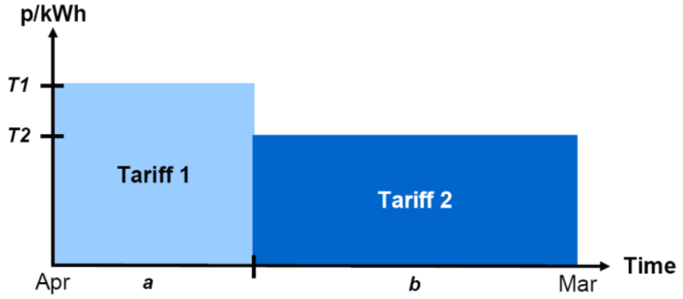
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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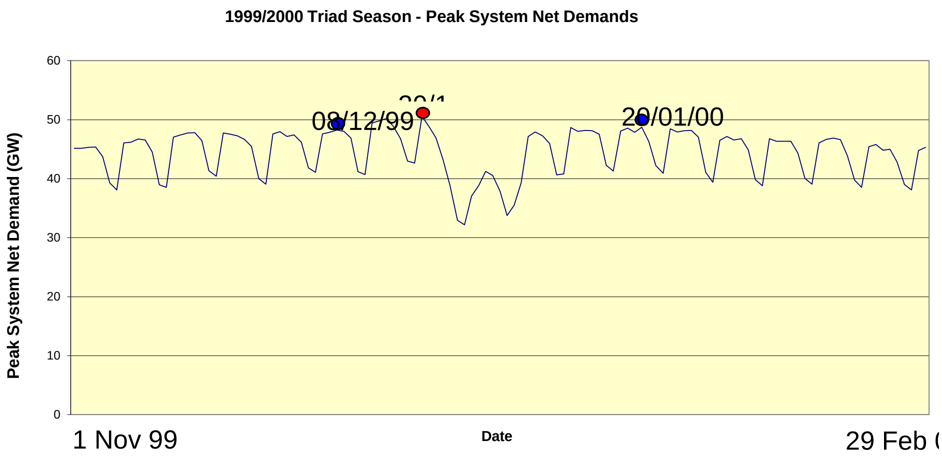


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.

If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:



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iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User’s TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \mathbf{£0.89/kW}$$

b) Year Round tariff -
190.43km * £10.07/MWkm * 1.8 = **£3.45/kW**
1000

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

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Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

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$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

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¶
£779m - £140m - -£10m = £12.98/kW¶
50,000MW

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge $= (HHD_A - HHD_F) \times$ £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge $= (HHEE_A - HHEE_F) \times$ £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104

**= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHD_F$** = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

**$HHEE_A$** = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$HHEE_F$** = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

**$NHHC_A$** = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**$NHHC_F$** = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1st to March 31st, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| SUPPLIER | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

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| POWER STATION WITH A BILATERAL CONNECTION AGREEMENT | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** \| **Station Load BMU** \| **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br><br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br><br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><th colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</th></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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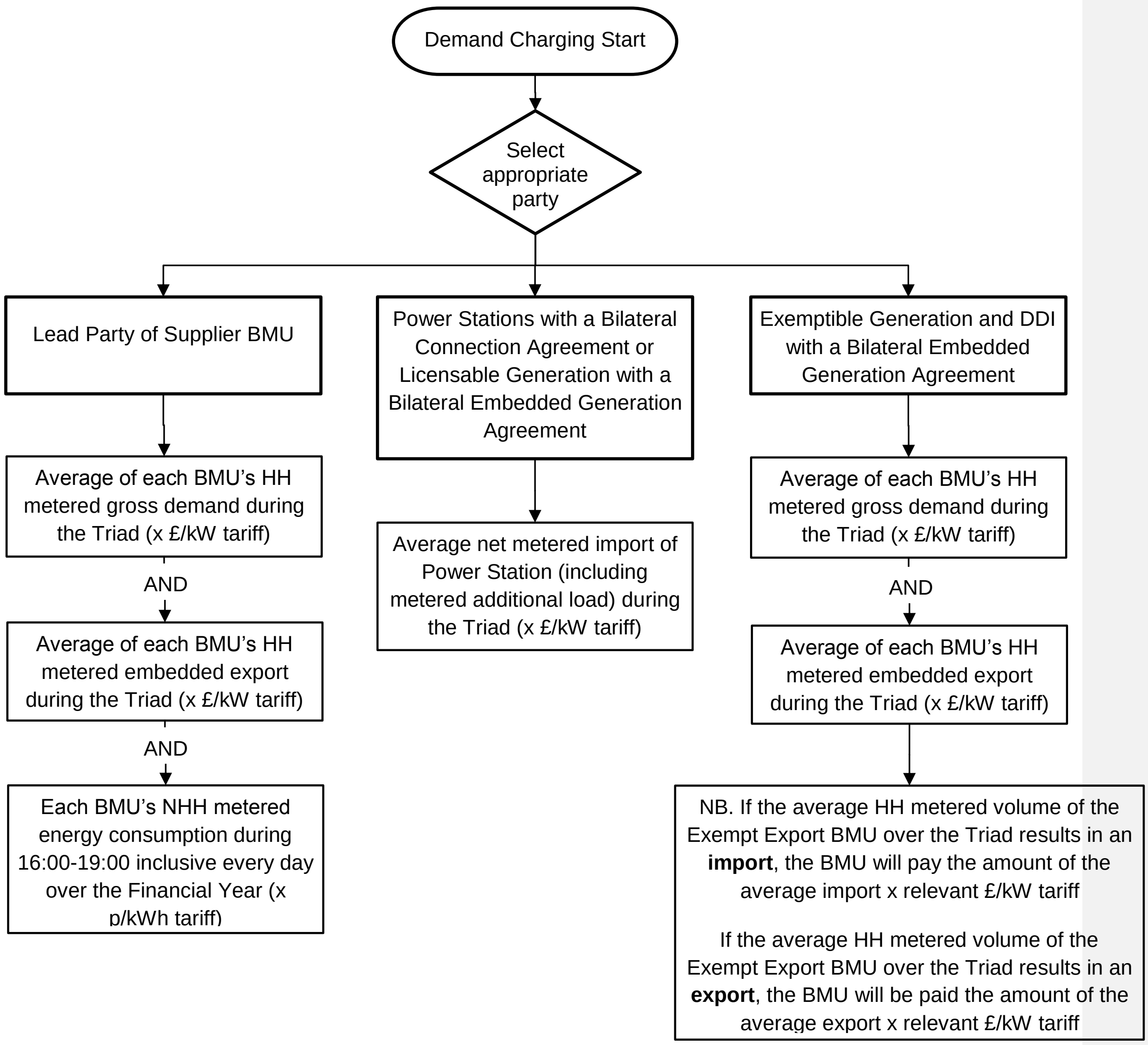
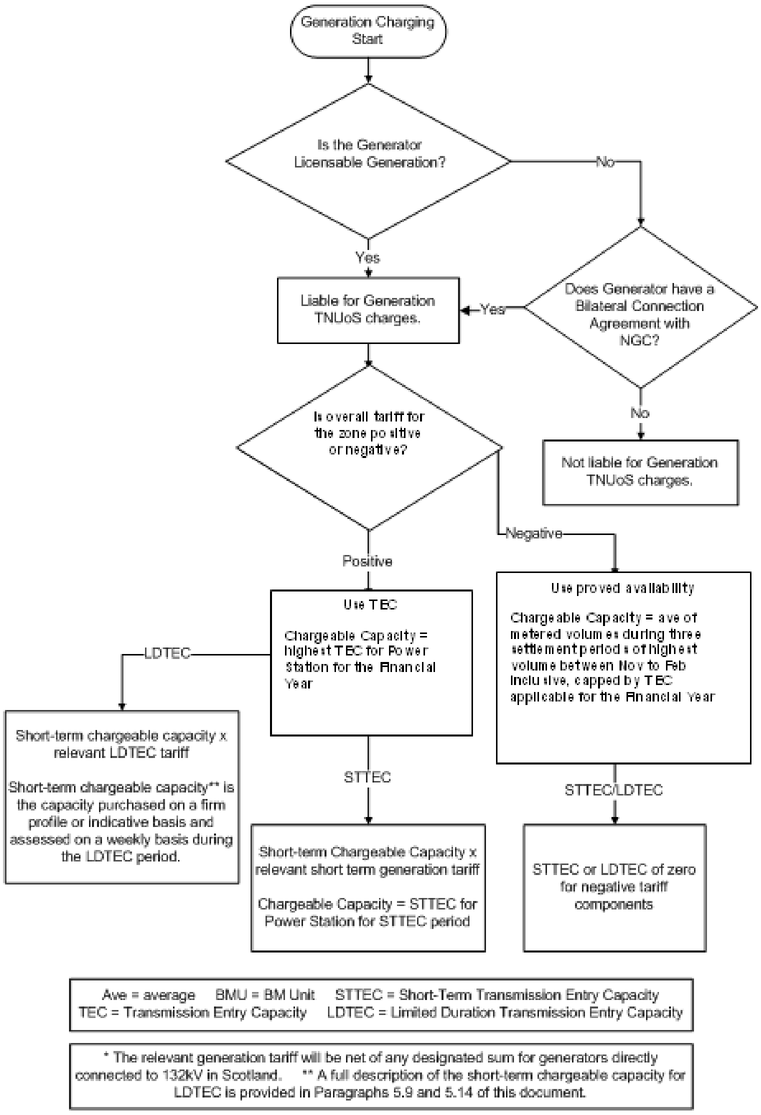



BMU = BM Unit DDI = Derogated Distribution Interconnector
HH = Half hourly NHH = Non-half hourly


Generation Charging Start
Is the Generator Licensable Generation?
No
Yes
Does Generator have a Bilateral Connection Agreement with NGC?
Yes
Liable for Generation TNUoS charges.
No
Not liable for Generation TNUoS charges.
Is overall tariff for the zone positive or negative?
Negative
Positive
Use TEC
Chargeable Capacity = highest TEC for Power Station for the Financial Year
Use proved availability
Chargeable Capacity = ave of metered volumes during three settlement periods of highest volume between Nov to Feb inclusive, capped by TEC applicable for the Financial Year
LDTEC
Short-term chargeable capacity x relevant LDTEC tariff
Short-term chargeable capacity** is the capacity purchased on a firm profile or indicative basis and assessed on a weekly basis during the LDTEC period.
STTEC
Short-term Chargeable Capacity x relevant short term generation tariff
Chargeable Capacity = STTEC for Power Station for STTEC period
STTEC/LDTEC
STTEC or LDTEC of zero for negative tariff components
Ave = average BMU = BM Unit STTEC = Short-Term Transmission Entry Capacity
TEC = Transmission Entry Capacity LDTEC = Limited Duration Transmission Entry Capacity
* The relevant generation tariff will be net of any designated sum for generators directly connected to 132kV in Scotland. ** A full description of the short-term chargeable capacity for LDTEC is provided in Paragraphs 5.9 and 5.14 of this document.

## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

$F = T$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

$F = T * D/P$

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

### iii) Half-Hourly (HH) Metered Demand Forecast – New User

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

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where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2005 to 31st March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10th June 2005 to 30th June 2005)

M = 1,000 kWh (period 1st July 2005 to 31st July 2005)

R = 20,000,000,000 kWh (period 1st July 2004 to 31st March 2005)

W = 2,000,000,000 kWh (period 1st July 2004 to 31st July 2004)

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## 14.15 Derivation of the Transmission Network Use of System Tariff

14.15.1 The Transmission Network Use of System (TNUoS) Tariff comprises two separate elements. Firstly, a locationally varying element derived from the DCLF ICRP transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

14.15.2 For generation TNUoS tariffs the locational element itself is comprised of five separate components. Three wider components –

- Wider Peak Security Component
- Wider Year Round Not-shared component
- Wider Year Round component

These components reflect the costs of the wider network under the different generation backgrounds set out in the Demand Security Criterion (for Peak Security component) and Economy Criterion (for both Year Round components) of the Security Standard. The two Year Round components reflect the unshared and shared costs of the wider network based on the diversity of generation plant types.

Two local components –

- Local substation, and
- Local circuit

These components reflect the costs of the local network.

Accordingly, the wider tariff represents the combined effect of the three wider locational tariff components and the residual element; and the local tariff represents the combination of the two local locational tariff components.

14.15.3 The process for calculating the TNUoS tariff is described below.

### The Transport Model

#### Model Inputs

14.15.4 The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak demand conditions using both Peak Security and Year Round generation backgrounds on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

14.15.5 The transport model requires a set of inputs representative of the Demand Security and Economy Criterion set out in the Security Standards. These conditions on the transmission system are represented in the Peak Security and Year Round background respectively as follows:

- Nodal generation information per node (TEC, plant type and SQSS scaling factors)
- Nodal net demand information
- Transmission circuits between these nodes
- The associated lengths of these routes, the proportion of which is overhead line or cable and the respective voltage level
- The cost ratio of each of 132kV overhead line, 132kV underground cable, 275kV overhead line, 275kV underground cable and 400kV underground cable to 400kV overhead line to give circuit expansion factors
- The cost ratio of each separate sub-sea AC circuit and HVDC circuit to 400kV overhead line to give circuit expansion factors
- 132kV overhead circuit capacity and single/double route construction information is used in the calculation of a generator's local charge.
- Offshore transmission cost and circuit/substation data

14.15.6 For a given charging year "t", the nodal generation TEC figure and generation plant types at each node will be based on the Applicable Value for year "t" in the NETS Seven Year Statement in year "t-1" plus updates to the October of year "t-1". The contracted TECs and generation plant types in the NETS Seven Year Statement include all plant belonging to generators who have a Bilateral Agreement with the TOs. For example, for 2010/11 charges, the nodal generation data is based on the forecast for 2010/11 in the 2009 NETS Seven Year Statement plus any data included in the quarterly updates in October 2009.

14.15.7 Scaling factors for different generation plant types are applied on their aggregated capacity for both Peak Security and Year Round backgrounds. The scaling is either Fixed or Variable (depending on the total demand level) in line with the factors used in the Security Standard, for example as shown in the table below.

| Generation Plant Type | Peak Security Background | Year Round Background |
|---|---|---|
| Intermittent | Fixed (0%) | Fixed (70%) |
| Nuclear & CCS | Variable | Fixed (85%) |
| Interconnectors | Fixed (0%) | Fixed (100%) |
| Hydro | Variable | Variable |
| Pumped Storage | Variable | Fixed (50%) |
| Peaking | Variable | Fixed (0%) |
| Other (Conventional) | Variable | Variable |

These scaling factors and generation plant types are set out in the Security Standard. These may be reviewed from time to time. The latest version will be used in the calculation of TNUoS tariffs and is published in the Statement of Use of System Charges

14.15.8 National Grid will categorise plant based on the categorisations described in the Security Standard. Peaking plant will include oil and OCGT technologies and Other (Conv.) represents all remaining conventional plant not explicitly stated elsewhere in the table In the event that a power station is made up of more than one technology type, the type of the higher Transmission Entry Capacity (TEC) would apply.

14.15.9 Nodal net demand data for the transport model will be based upon the GSP net demand that Users have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

14.15.10 Subject to paragraphs 14.15.15 to 14.15.22, Transmission circuits for charging year "t" will be defined as those with existing wayleaves for the year "t" with the associated lengths based on the circuit lengths indicated for year "t" in the April NETS Seven Year Statement for year "t-1" plus updates to October of year "t-1". If certain circuit information is not explicitly contained in the NETS Seven Year Statement, The Company will use the best information available.

14.15.11 The circuit lengths included in the transport model are solely those, which relate to assets defined as 'Use of System' assets.

14.15.12 For HVDC circuits, the impedance will be calculated to provide flows based on a ratio of the capacity provided by the HVDC link relative to the capacities on all major transmission system boundaries that it parallels.

14.15.13 The transport model employs the use of circuit expansion factors to reflect the difference in cost between (i) AC Circuits and HVDC circuits, (ii) underground and sub-sea circuits, (iii) cabled circuits and overhead line circuits, (iv) 132kV and 275kV circuits, (v) 275kV circuits and 400kV circuits, and (vi) uses 400kV overhead line (i.e. the 400kV overhead line expansion factor is 1). As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit (specifically HVDC and sub-sea cables of various voltages, 400kV underground cable, 275kV overhead line, 275kV underground cable, 132kV overhead line and 132kV underground cable) is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line. When calculating the local circuit tariff for a generator, alternative 132kV and offshore expansion factors to those used in the remainder of the tariff calculation are applied to the generator's local circuits.

14.15.14 The circuit expansion factors for HVDC circuits and AC subsea cables are determined on a case by case basis using the costs which are specific to individual projects containing HVDC or AC subsea circuits.

**Adjustments to Model Inputs associated with One-off Works**

14.15.15 Where, following the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge that related to One-off Works carried out on an onshore circuit, and such One-off Works would affect the value of a TNUoS tariff paid by the User, the transport model inputs associated with the onshore circuit shall be adjusted by The Company to reflect the asset value that would have been modelled if the works had been undertaken on the basis of the original asset design rather than the One-off Works.

14.15.16 Subject to paragraphs 14.15.17 to 14.15.19, where, prior to the implementation of CUSC Modification CMP203, a User has paid a One-Off Charge (or has paid a charge to the relevant TO prior to 1st April 2005 on the same principles as a

One-Off Charge) that related to works equivalent to those described under paragraph 14.15.15, an adjustment equivalent to that under paragraph 14.15.15 shall be made to the transport model inputs as follows.

14.15.17 Such adjustment shall be made following a User's request, which must be received by The Company no later than the second occurrence of 31st December following the implementation of CUSC Modification CMP203.

14.15.18 The Company shall only make an adjustment to the transport model inputs, under paragraph 14.15.16 where the charge was paid to the relevant TO prior to 1st April 2005 where evidence has been provided by the User that satisfies The Company that works equivalent to those under paragraph 14.15.15 were funded by the User.

14.15.19 Where a User has sufficient reason to believe that adjustments under paragraph 14.15.18 should be made in relation to specific assets that affect a TNUoS tariff that applies to one of its sites and outlines its reasoning to The Company, The Company shall (upon the User's request and subject to the User's payment of reasonable costs incurred by The Company in doing so) use its reasonable endeavours to assist the User in obtaining any evidence The Company or a TO may have to support its position.

14.15.20 Where a request is made under paragraph 14.15.16 on or prior to 31st December in a charging year, and The Company is satisfied based on the accompanying evidence provided to The Company under paragraph 14.15.17 that it is a valid request, the transport model inputs shall be adjusted accordingly and taken into account in the calculation of TNUoS tariffs effective from the year commencing on the 1st April following this and otherwise from the next subsequent 1st April.

14.15.21 The following table provides examples of works for which adjustments to transport model inputs would typically apply:

| **Ref** | **Description of works** | **Adjustments** |
|---|---|---|
| 1 | Undergrounding - A User requests to underground an overhead line at a greater cost. | As the cable cost will be more expensive than the overhead line (OHL) equivalent, the circuit will be modelled as an OHL. |
| 2 | Substation Siting Decision - A User requests to move the existing or a planned substation location to a place that means that the works cannot be justified as economic by the TO. | As the revised substation location may result in circuits being extended. If this is the case, the originally designed circuit lengths (as per the originally designed substation location) would be used in the transport model. |
| 3 | Circuit Routing Decision - A User asks to move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | As any circuit route changes that extend circuits are likely to result in a greater TNUoS tariff, the originally designed circuit lengths would be used in the transport model. |

| Ref | Description of works | Adjustments |
|---|---|---|
| 4 | Building circuits at lower voltages - A User requests lower tower height and therefore a different voltage. | As lower voltage circuits result in a higher expansion factor being used, the circuits would be modelled at the originally designed higher voltage. |

14.15.22 The following table provides examples of works for which adjustments to transport model typically would not apply:

| Ref | Description of works | Reasoning |
|---|---|---|
| 1 | Undergrounding - A User chooses to have a cable installed via a tunnel rather than buried. | Cable expansion factors are applied in the transport model regardless of whether a cable is tunnelled and buried, so there is no increased TNUoS cost. |
| 2 | Additional circuit route works - A User asks for screening to be provided around a new or existing circuit route. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 3 | Additional circuit route works - A User requests that a planned overhead line route is built using alternative transmission tower designs. | Circuit expansion factors are applied in the transport model irrespective of these works, so there is no increased TNUoS cost. |
| 4 | Additional substation works - A User asks for screening to be provided around a new or existing substation. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 5 | Additional substation works - Changes to connection assets (e.g. HV-LV transformers and associated switchgear), metering, additional LV supplies, additional protection equipment, additional building works, etc. | The additional substation works will not affect the User's TNUoS charge as there is no effect on power flows or circuit costs within the transport model. |
| 6 | Diversion - A User asks to temporarily move an existing or a planned circuit route in a way in which the works cannot be justified as economic by the TO. | The temporary circuit changes will not be incorporated into the transport model. |

| | | |
|---|---|---|
| 7 | Connection Entry Capacity (CEC) before Transmission Entry Capacity (TEC). A User asks for a connection in a year prior to the relating TEC; i.e. physical connection without capacity. | No additional works are being undertaken, works are simply being completed well in advance of the generator commissioning. The One-Off Charge reflects the depreciated value of the assets prior to commissioning (and any TNUoS being charged). |
| 8 | Early asset replacement - An asset is replaced prior to the end of its expected life. | As the asset is simply replaced, no data in the transport model is expected to change. |
| 9 | Additional Engineering/ Mobilisation costs - A User requests changes to the planned works, that results in additional operational costs. | The data in the transport model is unaffected. |
| 10 | Offshore (Generator Build) - Any of the works described above or under paragraph 14.15.18. | The value of the works will not form part of the asset transfer value therefore will not be used as part of the offshore tariff calculation. |
| 11 | Offshore (Offshore Transmission Owner (OFTO) Build) - Any of the works described above or under paragraph 14.15.18. | As part of determining the TNUoS revenue associated with each asset, the value of the One-Off Works would be excluded when pro-rating the OFTO's allowed revenue against assets by asset value. |

14.15.23 The Company shall publish any adjusted transport model inputs that it intends to use in the calculation of TNUoS tariffs effective from the year commencing on the following 1st April in the NETS Seven Year Statement October Update. Any further adjustments that The Company makes shall be published by The Company upon the publication of the final TNUoS tariffs for the year concerned.

**Model Outputs**

14.15.24 The transport model takes the inputs described above and carries out the following steps individually for Peak Security and Year Round backgrounds.

14.15.25 Depending on the background, the TEC of the relevant generation plant types are scaled by a percentage as described in 14.15.7, above. The TEC of the remaining generation plant types in each background are uniformly scaled such that total national generation (scaled sum of contracted TECs) equals total national ACS Demand.

14.15.26 For each background, the model then uses a DCLF ICRP transport algorithm to derive the resultant pattern of flows based on the network impedance required to meet the nodal net demand using the scaled nodal generation, assuming every circuit has infinite capacity. Flows on individual transmission circuits are compared for both backgrounds and the background giving rise to

the highest flow is considered as the triggering criterion for future investment of that circuit for the purposes of the charging methodology. Therefore all circuits will be tagged as Peak Security or Year Round depending upon the background resulting in the highest flow. In the event that both backgrounds result in the same flow, the circuit will be tagged as Peak Security. Then it calculates the resultant total network Peak Security MWkm and Year Round MWkm, using the relevant circuit expansion factors as appropriate.

14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (net demand) distributed across all demand nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW offtake allocated to any given demand node will be based on total background nodal net demand in the model. For example, with a total GB net demand of 60GW in the model, a node with a net demand of 600MW would contain 1% of the offtake i.e. 0.01MW.

14.15.28 Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a Peak Security marginal km cost and a Year Round marginal km cost for generation at each node (although not that used to calculate generation tariffs which considers local and wider cost components). The Peak Security and Year Round marginal km costs for demand at each node are equal and opposite to the Peak Security and Year Round nodal marginal km respectively for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total circuit km.

14.15.29 Using a similar methodology as described above in 14.15.27, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake across the distributed reference node. It should be noted that although the wider marginal km costs are calculated for both Peak Security and Year Round backgrounds, the local marginal km costs are calculated on the Year Round background.

14.15.30 In addition, any circuits in the model, identified as local assets to a node will have the local circuit expansion factors which are applied in calculating that particular node's marginal km. Any remaining circuits will have the TO specific wider circuit expansion factors applied.

14.15.31 An example is contained in 14.21 Transport Model Example.

### Calculation of local nodal marginal km

14.15.32 In order to ensure assets local to generation are charged in a cost reflective manner, a generation local circuit tariff is calculated. The nodal specific charge provides a financial signal reflecting the security and construction of the infrastructure circuits that connect the node to the transmission system.

14.15.33 Main Interconnected Transmission System (MITS) nodes are defined as:

- Grid Supply Point connections with 2 or more transmission circuits connecting at the site; or
- connections with more than 4 transmission circuits connecting at the site.

14.15.34 Where a Grid Supply Point is defined as a point of supply from the National Electricity Transmission System to network operators or non-embedded customers excluding generator or interconnector load alone. For the avoidance of doubt, generator or interconnector load would be subject to the circuit component of its Local Charge. A transmission circuit is part of the National Electricity Transmission System between two or more circuit-breakers which includes transformers, cables and overhead lines but excludes busbars and generation circuits.

14.15.35 Generators directly connected to a MITS node will have a zero local circuit tariff.

14.15.36 Generators not connected to a MITS node will have a local circuit tariff derived from the local nodal marginal km for the generation node i.e. the increase or decrease in marginal km along the transmission circuits connecting it to all adjacent MITS nodes (local assets).

## Calculation of zonal marginal km

14.15.37 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. The full criteria for determining generation zones are outlined in paragraph 14.15.42. The number of generation zones set for 2010/11 is 20.

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 The nodal marginal km are amalgamated into zones by weighting them by their relevant generation or demand capacity.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

| | | |
|---|---|---|
| Gi | = | Generation zone |
| j | = | Node |
| $NMkm_{PS}$ | = | Peak Security Wider nodal marginal km from transport model |
| $WNMkm_{PS}$ | = | Peak Security Weighted nodal marginal km |
| $ZMkm_{PS}$ | = | Peak Security Zonal Marginal km |

Gen = Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

| | | |
|---|---|---|
| $NMkm_{YR}$ | = | Year Round Wider nodal marginal km from transport model |
| $WNMkm_{YR}$ | = | Year Round Weighted nodal marginal km |
| $ZMkm_{YR}$ | = | Year Round Zonal Marginal km |
| Gen | = | Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model |

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{jPS} = \frac{-1 * NMkm_{jPS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiPS} = \sum_{j \in Di} WNMkm_{jPS}$$

Where:

| | | |
|---|---|---|
| Di | = | Demand zone |
| Dem | = | Nodal Net Demand from transport model |

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.15.42 A number of criteria are used to determine the definition of the generation zones. Whilst it is the intention of The Company that zones are fixed for the duration of a price control period, it may become necessary in exceptional circumstances to review the boundaries having been set. In both circumstances, the following criteria are used to determine the zonal boundaries:

i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs

from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

ii.) The nodes within zones should be geographically and electrically proximate.

iii.) Relevant nodes are considered to be those with generation connected to them as these are the only ones, which contribute to the calculation of the zonal generation tariff.

14.15.43 The process behind the criteria in 14.15.42 is driven by initially applying the nodal marginal costs from the relevant generation background within the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs from the relevant generation background for guidance.

14.15.44 The zoning criteria are applied to a reasonable range of DCLF ICRP transport model scenarios, the inputs to which are determined by The Company to create appropriate TNUoS generation zones. The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, The Company determines and uses the one that best reflects the physical system boundaries.

14.15.45 Zones will typically not be reviewed more frequently than once every price control period to provide some stability. However, in exceptional circumstances, it may be necessary to review zoning more frequently to maintain appropriate, cost reflective, locational cost signals. For example, if a new generator connecting to the transmission system would cause the creation of a new generation zone for that generator alone, it may not be appropriate from a cost reflective perspective to wait until the next price control period to undertake this rezoning. If any such rezoning is required, it will be undertaken against a background of minimal change to existing generation zones and in line with the notification process set out in the Transmission Licence and CUSC.

**Accounting for Sharing of Transmission by Generators**

14.15.46 A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff.

14.15.47 The sharing between different generation types is accounted for by (a) using transmission network boundaries between generation zones set by connectivity between generation charging zones, and (b) the proportion of Low Carbon and Carbon generation behind these boundaries.

14.15.48 The zonal incremental km for each generation charging zone is split into each boundary component by considering the difference between it and the neighbouring generation charging zone using the formula below;

$$BIkm_{ab} = ZIkm_b - ZIkm_a$$

Where;
$BIkm_{ab}$ = boundary incremental km between generation charging zone A and generation charging zone B
ZIkm = generation charging zone incremental km.

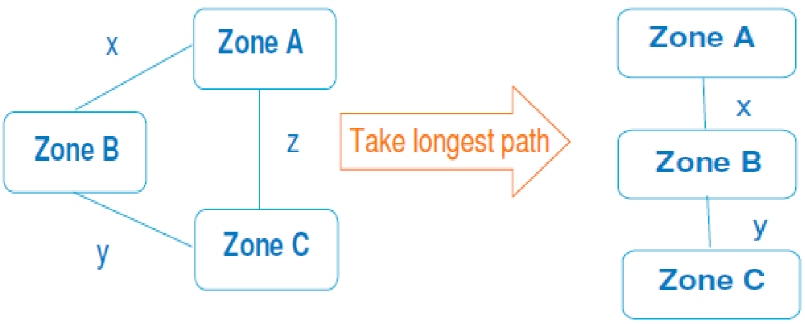
14.15.49 The table below shows the categorisation of Low Carbon and Carbon generation. This table will be updated by National Grid in the Statement of Use of System Charges as new generation technologies are developed.

| **Carbon** | **Low Carbon** |
|---|---|
| Coal | Wind |
| Gas | Hydro (excl. Pumped Storage) |
| Biomass | Nuclear |
| Oil | Marine |
| Pumped Storage | Tidal |
| Interconnectors | |

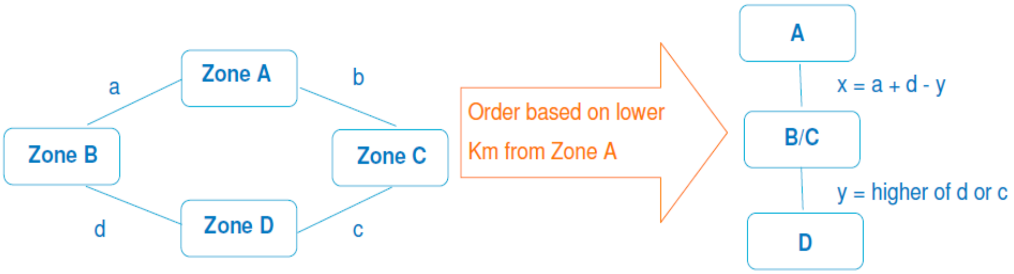
Determination of Connectivity

14.15.50 Connectivity is based on the existence of electrical circuits between TNUoS generation charging zones that are represented in the Transport model. Where such paths exist, generation charging zones will be effectively linked via an incremental km transmission boundary length. These paths will be simplified through in the case of;

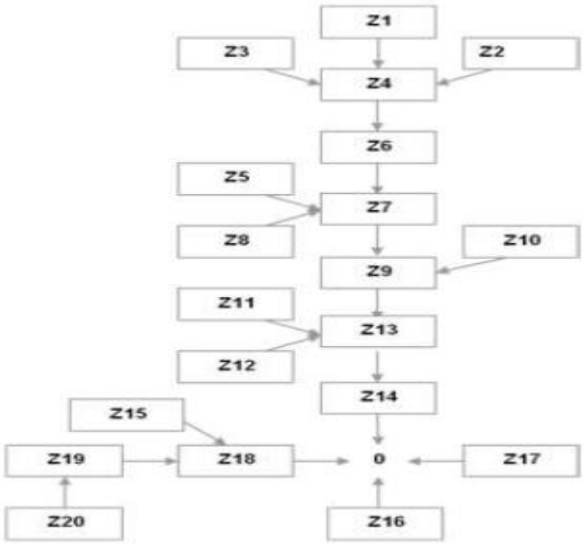
- Parallel paths – the longest path will be taken. An illustrative example is shown below with x, y and z representing the incremental km between zones.




- Parallel zones – parallel zones will be amalgamated with the incremental km immediately beyond the amalgamated zones being the greater of those existing prior to the amalgamation. An illustrative example is shown below with a, b, c, and d representing the the initial incremental km between zones, and x and y representing the final incremental km following zonal amalgamation.




14.15.51 An illustrative Connectivity diagram is shown below:




The arrows connecting generation charging zones and amalgamated generation charging zones represent the incremental km transmission boundary lengths towards the notional centre of the system. Generation located in charging zones behind arrows is considered to share based on the ratio of Low Carbon to Carbon cumulative generation TEC within those zones.

14.15.52 The Company will review Connectivity at the beginning of a new price control period, and under exceptional circumstances such as major system reconfigurations or generation rezoning. If any such reassessment is required, it will be undertaken against a background of minimal change to existing Connectivity and in line with the notification process set out in the Transmission Licence and the CUSC.

Calculation of Boundary Sharing Factors

14.15.53 Boundary sharing factors (BSFs) are derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths using the following formulae –

If $\frac{LC}{LC+C} \leq 0.5$, then all Year round marginal km costs are shared i.e. the BSF is 100%.

Where:
LC = Cumulative Low Carbon generation TEC behind the relevant transmission boundary
C = Cumulative Carbon generation TEC behind the relevant transmission boundary

If $\frac{LC}{LC+C} \rangle 0.5$ then the BSF is calculated using the following formula: -

$$BSF = \left( -2 \times \left( \frac{LC}{LC+C} \right) \right) + 2$$

Where:
BSF = boundary sharing factor.

14.15.54 The shared incremental km for each boundary are derived from the multiplication of the boundary sharing factor by the incremental km for that boundary;

$$SBIkm_{ab} = BIIkm_{ab} \ x \ BSF_{ab}$$

Where;
$SBIkm_{ab}$ = shared boundary incremental km between generation charging zone A and generation charging zone B
$BSF_{ab}$ = generation charging zone boundary sharing factor.

14.15.55 The shared incremental km is discounted from the incremental km for that boundary to establish the not-shared boundary incremental km. The not-shared boundary incremental km reflects the cost of transmission investment on that boundary accounting for the sharing of power stations behind that boundary.

$$NSBIkm_{ab} = BIkm_{ab} - SBIkm_{ab}$$

Where;
$NSBIkm_{ab}$ = not shared boundary incremental km between generation charging zone A and generation charging zone B.

14.15.56 The shared incremental km for a generation charging zone is the sum of the appropriate shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_{a}^{n} NSBIkm_{ab} = ZMkm_{nYRS}$$

Where;
$ZMkm_{nYRS}$ = Year Round Shared Zonal Marginal km for generation charging zone n.

14.15.57 The not-shared incremental km for a generation charging zone is the sum of the appropriate not-shared boundary incremental km for that generation charging zone as derived from the connectivity diagram.

$$\sum_a^n NSBIkm_{ab} = ZMkm_{nYRNS}$$

Where;

$ZMkm_{nYRNS}$ = Year Round Not-Shared Zonal Marginal km for generation zone n.

## Deriving the Final Local £/kW Tariff and the Wider £/kW Tariff

14.15.58 The zonal marginal km ($ZMkm_{Gi}$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and the **Locational Security Factor** (see below). The nodal local marginal km ($NLMkm^L$) are converted into costs and hence a tariff by multiplying by the **Expansion Constant** and a **Local Security Factor**.

### The Expansion Constant

14.15.59 The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion.

14.15.60 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.95 – 14.15.117, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.133.

14.15.61 The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices, making the tariffs as forward looking as possible. This cost data represents The Company's best view; however it is considered as commercially sensitive and is therefore treated as confidential. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

14.15.62 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.70 – 14.15.77. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.63 The table below shows the first stage in calculating the onshore expansion constant. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV OHL using example data:

| 400kV OHL expansion constant calculation | | | | | |
|---|---|---|---|---|---|
| **MW** | **Type** | **£(000)/k** | **Circuit km*** | **£/MWkm** | **Weight** |
| A | B | C | D | E = C/A | F=E*D |
| 6500 | La | 700 | 500 | 107.69 | 53846 |
| 6500 | Lb | 780 | 0 | 120.00 | 0 |
| 3500 | La/b | 600 | 200 | 171.43 | 34286 |
| 3600 | Lc | 400 | 300 | 111.11 | 33333 |
| 4000 | Lc/a | 450 | 1100 | 112.50 | 123750 |
| 5000 | Ld | 500 | 300 | 100.00 | 30000 |
| 5400 | Ld/a | 550 | 100 | 101.85 | 10185 |
| *Sum* | | | **2500 (G)** | | **285400 (H)** |
| | | | | **Weighted Average (J= H/G):** | **114.160 (J)** |

*These are circuit km of types that have been provided in the previous 10 years. If no information is available for a particular category the best forecast will be used.

14.15.64 The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by an annuity factor. The formula used to calculate of the annuity factor is shown below:

$$Annuityfac\,tor = \frac{1}{\left[\frac{\left(1-(1+WACC)^{-AssetLife}\right)}{WACC}\right]}$$

14.15.65 The Weighted Average Cost of Capital (WACC) and asset life are established at the start of a price control and remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated at the start of a price control period. These assumptions provide a current annuity factor of 0.066.

14.15.66 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an 'overhead factor'. The 'overhead factor' represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated at the start of each price control period. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.67 Using the previous example, the final steps in establishing the expansion constant are demonstrated below:

| 400kV OHL expansion constant calculation | Ave £/MWkm |
|---|---|
| **OHL** | 114.160 |

| | |
|---|---:|
| Annuitised | 7.535 |
| Overhead | 2.055 |
| **Final** | **9.589** |

14.15.68 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.73, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.78.

14.15.69 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out for the first year of the price control and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

**Onshore Wider Circuit Expansion Factors**

14.15.70 Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The factors are then derived by dividing the calculated expansion constant by the 400kV overhead line expansion constant. The factors will be fixed for each respective price control period.

14.15.71 In calculating the onshore underground cable factors, the forecast costs are weighted equally between urban and rural installation, and direct burial has been assumed. The operating costs for cable are aligned with those for overhead line. An allowance for overhead costs has also been included in the calculations.

14.15.72 The 132kV onshore circuit expansion factor is applied on a TO basis. This is to reflect the regional variation of plans to rebuild circuits at a lower voltage capacity to 400kV. The 132kV cable and line factor is calculated on the proportion of 132kV circuits likely to be uprated to 400kV. The 132kV expansion factor is then calculated by weighting the 132kV cable and overhead line costs with the relevant 400kV expansion factor, based on the proportion of 132kV circuitry to be uprated to 400kV. For example, in the TO areas of National Grid and Scottish Power where there are no plans to uprate any 132kV circuits, the full cable and overhead line costs of 132kV circuit are reflected in the 132kV expansion factor calculation.

14.15.73 The 275kV onshore circuit expansion factor is applied on a GB basis and includes a weighting of 83% of the relevant 400kV cable and overhead line factor. This is to reflect the averaged proportion of circuits across all three Transmission Licensees which are likely to be uprated from 275kV to 400kV across GB within a price control period.

14.15.74 The 400kV onshore circuit expansion factor is applied on a GB basis and reflects the full costs for 400kV cable and overhead lines.

14.15.75 AC sub-sea cable and HVDC circuit expansion factors are calculated on a case by case basis using actual project costs (Specific Circuit Expansion Factors).

14.15.76 For HVDC circuit expansion factors both the cost of the converters and the cost of the cable are included in the calculation.

14.15.77 The TO specific onshore circuit expansion factors calculated for 2008/9 (and rounded to 2 decimal places) are:

Scottish Hydro Region

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 27.79 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.24 |

Scottish Power & National Grid Regions

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor: | 2.80 |

**Onshore Local Circuit Expansion Factors**

14.15.78 The local onshore circuit tariff is calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated.

14.15.79 In addition, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

| | |
|---|---|
| 400kV underground cable factor: | 22.39 |
| 275kV underground cable factor: | 22.39 |
| 132kV underground cable factor: | 30.22 |
| 400kV line factor: | 1.00 |
| 275kV line factor: | 1.14 |
| 132kV line factor (single; <200MVA): | 10.00 |
| 132kV line factor (double; <200MVA): | 8.32 |
| 132kV line factor (single; >=200MVA): | 7.13 |
| 132kV line factor (double; >=200MVA): | 4.42 |

**Offshore Circuit Expansion Factors**

14.15.80 Offshore expansion factors (£/MWkm) are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are Offshore Transmission Owner and circuit specific. Each Offshore Transmission Owner will periodically provide, via the STC, information to derive an annual circuit revenue requirement. The offshore circuit revenue shall include revenues associated with the Offshore Transmission Owner's reactive compensation equipment, harmonic filtering equipment, asset spares and HVDC converter stations.

14.15.81 In the first year of connection, the offshore circuit expansion factor would be calculated as follows:

$$\frac{CRevOFTO1}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| CRevOFTO1 | = | The offshore circuit revenue in £ for Year 1 |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.82 In all subsequent years, the offshore circuit expansion factor would be calculated as follows:

$$\frac{AvCRevOFTO}{L \times CircRat} \div Onshore\,400kV\ OHL\ Expansion\ Constant$$

Where:

| | | |
|---|---|---|
| AvCRevOFTO | = | The annual offshore circuit revenue averaged over the remaining years of the onshore National Electricity Transmission System Operator (NETSO) price control |
| L | = | The total circuit length in km of the offshore circuit |
| CircRat | = | The continuous rating of the offshore circuit |

14.15.83 For the avoidance of doubt, the offshore circuit revenue values, $CRevOFTO1$ and $AvCRevOFTO$ shall be determined using asset values after the removal of any One-Off Charges.

14.15.84 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be recalculated at the start of each price control period using the formula in paragraph 14.15.71. For each subsequent year within the price control period, these expansion factors will be adjusted by the annual Offshore Transmission Owner specific indexation factor, *OFTOInd*, calculated as follows;

$$OFTOInd_{t,f} = \frac{OFTO\mathrm{Re}vInd_{t,f}}{RPI_t}$$

where:

| | | |
|---|---|---|
| $OFTOInd_{t,f}$ | = | the indexation factor for Offshore Transmission Owner *f* in respect of charging year *t*; |
| $OFTORevInd_{t,f}$ | = | the indexation rate applied to the revenue of Offshore Transmission Owner *f* under the terms of its Transmission Licence in respect of charging year *t*; and |
| $RPI_t$ | = | the indexation rate applied to the expansion constant in respect of charging year *t*. |

**Offshore Interlinks**

14.15.85 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each User will be based on the Measure of Capacity to the MITS using the Offshore Interlink(s) in the event of a single circuit fault on the User's circuit from their offshore substation towards the shore, compared to the Measure of Capacity of the other Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the User's ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.

A *Single Common Substation* is a substation where:

i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

The Measure of Capacity to the MITS for each Offshore substation is the result of the following formula or zero whichever is larger. For the situation with only one interlink, all terms relating to C should be set to zero:

For Substation A:
$\min \{ Cap_{IAB}, ILF_A \times TEC_A - RCap_A, Cap_B - ILF_B \times TEC_B + \min (Cap_{IBC}, Cap_C - ILF_C \times TEC_C ) \}$

For Substation B:
$\min \{ ILF_B \times TEC_B - RCap_{B,} \min (Cap_{IAB}, Cap_A - ILF_A \times TEC_A ) + \min ( Cap_{IBC}, Cap_C - ILF_C \times TEC_C) \}$

For Substation C:
$\min \{ Cap_{IBC}, ILF_C \times TEC_{C\,-} - RCap_C, Cap_B - ILF_B \times TEC_B + \min (Cap_{IAB}, Cap_A – ILF_A \times TEC_A ) \}$
and

$Cap_{IAB}$ = total capacity of the Offshore Interlink between substations A and B
$Cap_{IBC}$ = total capacity of the Offshore Interlink between substations B and C
$Cap_X$ = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
$TEC_X$ = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.

$ILF_X$ = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a station specific Annual Load Factor based on five years of data, the generic ALF for the fuel type will be used as the ILF for all stations. When all Users have a station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.86 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.85 applies in situations where the Offshore Interlink was included in the design phase, or if one or more User(s) has already financially committed or been commissioned then only where that User(s) agrees to the Offshore Interlink.

14.15.87 Alternatively to the formula specified in 14.15.85 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

a. All relevant Users shall notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all of the relevant Users.
d. If all relevant Users are unable to reach agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

**The Locational Onshore Security Factor**

14.15.88 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used for Zoning in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak net demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.89 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.90 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed for each price control period and fixed for the duration.

**Local Security Factors**

14.15.91 Local onshore security factors are generator specific and are applied to a generator's local onshore circuits. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.92 Where a Transmission Owner has designed a local onshore circuit (or otherwise that circuit once built) to a capacity lower than the aggregated TEC of the generation using that circuit, then the local security factor of 1.0 will be multiplied by a Counter Correlation Factor (CCF) as described in the formula below;

$$CCF = \frac{D_{\min} + T_{cap}}{G_{cap}}$$

Where; $D_{min}$ = minimum annual net demand (MW) supplied via that circuit in the absence of that generation using the circuit

$T_{cap}$ = transmission capacity built (MVA)

$G_{cap}$ = aggregated TEC of generation using that circuit

CCF cannot be greater than 1.0.

14.15.93 A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{NetworkExportCapacity}{\sum_k Gen_k}$$

Where:

NetworkExportCapacity = the total export capacity of the network disregarding any Offshore Interlinks

k = the generation connected to the offshore network

1 http://www.nationalgrid.com/uk/Electricity/Charges/

14.15.94 The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, derived as 1.8 for 2010/11.

14.15.95 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

$$LocalSF = \frac{\mathrm{IRevOFTO} \times \mathrm{NetworkExportCapacity}}{\mathrm{CRevOFTO} \times \sum_{k} \mathrm{Gen}_{k}} + LocalSF_{\mathrm{initial}}$$

Where:
IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.85
CRevOFTO = The offshore circuit revenue in £ associated with the circuit(s) from the offshore substation to the Single Common Substation.
$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.80 and 14.15.81
And other definitions as in 14.15.80.

**Initial Transport Tariff**

14.15.96 First an Initial Transport Tariff (ITT) must be calculated for both Peak Security and Year Round backgrounds. For Generation, the Peak Security zonal marginal km ($ZMkm_{PS}$), Year Round Not-Shared zonal marginal km ($ZMkm_{YRNS}$) and Year Round Shared zonal marginal km ($ZMkm_{YRS}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT, Year Round Not-Shared ITT and Year Round Shared ITT respectively:

$$ZMkm_{Gi\,PS} \times EC \times LSF = ITT_{Gi\,PS}$$
$$ZMkm_{GiYRNS} \times EC \times LSF = ITT_{GiYRNS}$$
$$ZMkm_{GiYRS} \times EC \times LSF = ITT_{GiYRS}$$

Where
$ZMkm_{GiPS}$ = Peak Security Zonal Marginal km for each generation zone
$ZMkm_{GiYRNS}$ = Year Round Not-Shared Zonal Marginal km for each generation charging zone
$ZMkm_{GiYRS}$ = Year Round Shared Zonal Marginal km for each generation charging zone

EC = Expansion Constant
LSF = Locational Security Factor
$ITT_{GiPS}$ = Peak Security Initial Transport Tariff (£/MW) for each generation zone
$ITT_{GiYRNS}$ = Year Round Not-Shared Initial Transport Tariff (£/MW) for each generation charging zone
$ITT_{GiYRS}$ = Year Round Shared Initial Transport Tariff (£/MW) for each generation charging zone.

14.15.97 Similarly, for demand the Peak Security zonal marginal km ( $ZMkm_{PS}$) and Year Round zonal marginal km ($ZMkm_{YR}$) are simply multiplied by the expansion constant and the locational security factor to give the Peak Security ITT and Year Round ITT respectively:

$$ZMkm_{Di\,PS} \times EC \times LSF = ITT_{Di\,PS}$$

$$ZMkm_{Di\,YR} \times EC \times LSF = ITT_{Di\,YR}$$

Where

| | | |
|---|---|---|
| $ZMkm_{DiPS}$ | = | Peak Security Zonal Marginal km for each demand zone |
| $ZMkm_{DiYR}$ | = | Year Round Zonal Marginal km for each demand zone |
| $ITT_{DiPS}$ | = | Peak Security Initial Transport Tariff (£/MW) for each demand one |
| $ITT_{DiYR}$ | = | Year Round Initial Transport Tariff (£/MW) for each demand zone |

14.15.98 The next step is to multiply these ITTs by the expected metered triad gross GSP group demand and generation capacity to gain an estimate of the initial revenue recovery for both Peak Security and Year Round backgrounds. The metered triad gross GSP group demand and generation capacity are based on analysis of forecasts provided by Users and are confidential.

Metered triad gross GSP group demand is net demand for all GSP groups less affected embedded exports and grandfathered embedded exports for all GSP groups.

a.

Where

| | | |
|---|---|---|
| $ITRR_G$ | = | Initial Transport Revenue Recovery for generation |
| $G_{Gi}$ | = | Total forecast Generation for each generation zone (based on analysis of confidential User forecasts) |
| $ITRR_D$ | = | Initial Transport Revenue Recovery for gross GSP group demand |
| $D_{Di}$ each | = | Total forecast Metered Triad gross GSP group Demand for demand zone (based on analysis of confidential User forecasts). |

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. Similarly, when calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below).

**Peak Security (PS) Flag**

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the

need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

| Generation Plant Type | PS flag |
|---|---|
| Intermittent | 0 |
| Other | 1 |

**Annual Load Factor (ALF)**

14.15.100 The ALF for each individual Power Station is calculated using the relevant TEC (MW) and corresponding output data. Where output data is not available for a Power Station, including for new Power Stations and emerging Power Station technologies, generic data for the appropriate generation plant type will be used.

14.15.101 For a given charging year "t" the Power Station ALF will be based on information from the previous five charging years, calculated for each charging year as set out below.

$$ALF = \frac{\sum_{p=1}^{17520} GMWh_p}{\sum_{p=1}^{17520} TECp \times 0.5}$$

Where:
$GMWh_p$ is the maximum of FPN or actual metered output in a Settlement Period related to the power station TEC (MW); and
$TEC_p$ is the TEC (MW) applicable to that Power Station for that Settlement Period including any STTEC and LDTEC, accounting for any trading of TEC.

14.15.102 The appropriate output (FPN or actual metered) figure is derived from **BM Unit** data available to National Grid and relates to the total TEC of the Power Station.

14.15.103 Once all five charging year ALFs have been calculated for the individual Power Station they are compared, and the highest and lowest figures are discarded. The final ALF, to be used for transmission charging purposes, is calculated as the average of the remaining three ALFs.

14.15.104 In the event that only four charging years of complete output (FPN or actual metered) data are available for an individual Power Station then the higher three charging years ALF would be used in the calculation of the final ALF. In the event that only three charging years of complete output (FPN or actual metered) data are available then these three charging years would be used.

14.15.105 Due to the aggregation of output (FPN or actual metered) data for dispersed generation (e.g. cascade hydro schemes), where a single generator BMU consists of geographically separated power stations, the ALF would be calculated based on the total output of the BMU and the overall TEC of those Power Stations.

14.15.106 In the event that there are not three full charging years of an individual power station's output available, missing output (FPN or actual metered) data would be replaced by generic data for that generation plant type to ensure three charging years of information are available for the Power Station. The derivation of the generic data is described in paragraphs 14.15.111-14.15.114.

14.15.107 Users will receive draft ALFs before 25th December of the charging year (t-1) for the charging year (t) and will have a period of 15 working days from date of publishing to notify the Company of any errors. Failure to agree changes relating to errors will be treated as a charging dispute under the CUSC.

14.15.108 The ALFs used in the setting of final tariffs will be published in the annual Statement of Use of System Charges. Changes to ALFs after this publication will not result in changes to published tariffs (e.g. following dispute resolution).

**Derivation of Generic ALFs**

14.15.109 The generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data, using an identical methodology to that used for the Power Station specific calculation described above. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used. Example generation plant type categories are listed below;

| **Fuel Type** |
|---|
| Biomass |
| Coal |
| Gas |
| Hydro |
| Nuclear (by reactor type) |
| Oil & OCGTs |
| Pumped Storage |
| Onshore Wind |
| Offshore Wind |
| CHP |

14.15.110 The Company will keep these categories under review and update as necessary. Where within a category there is a significant locational difference consideration will be given to zonal generic factors. The factors used will be published in the Statement of Use of System Charges and will be reviewed annually.

14.15.111 If a User can demonstrate that the generation plant type of a Power Station has changed, consideration will be given to the use of relevant generic ALF information in the calculation of their charges until sufficient specific data is available.

14.15.112 For new and emerging generation plant types, where insufficient data is available to allow a generic ALF to be developed, The Company will use the best information available e.g. from manufactuers and data from use of similar technologies outside GB. The factor will be agreed with the relevant Generator. In the event of a disagreement the standard provisions for dispute in the CUSC will apply.

**TNUoS Embedded Export Tariffs**

14.15.113 Embedded exports are exports measured on a half-hourly basis by Metering Systems, in accordance with the BSC, that are not subject to generation TNUoS. The tariff to be applied in respect of embedded exports is different depending on whether the embedded exports are affected embedded exports or grandfathered embedded exports

TNUoS Embedded Export Tariff for Affected Embedded Exports

14.15.114 Affected Embedded Exports are embedded exports other than Grandfathered Embedded Exports.

14.15.115 The embedded export tariff will be applied to the metered Triad volumes of Affected Embedded Exports for each demand zone as follows:

$$EETA_{Di} = ITT_{DiPS} + ITT_{DiYR} + AEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
AEX:

$$AEX = \frac{(p \times TRR) - OC - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14}(D_{Di} + EEV_{Di})}$$

Where
AEX= Residual Tariff for embedded Affected Embedded Exports
P = Proportion of revenue to be recovered from demand
OC = Offshore Costs paid by demand
$ITRR_{DPS}$ = Peak Security Initial Transport Revenue Recovery for demand
$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for demand
$D_{Di}$ = Total forecast Metered Triad Gross Demand for each demand zone $EEV_{Di}$ = Forecast Embedded Export metered volume at Triad (MW)

The Value of $EETA_{Di}$ will be floored at zero, so that $EETA_{Di}$ is always zero or positive.

TNUoS Embedded Export Tariff for Grandfathered Embedded Exports

14.15.116 Grandfathered Embedded Exports are embedded exports measured by metering systems where all associated generation either:

- Has a Contract for Difference Agreement that was awarded in allocation rounds prior to 01/01/2016 which has not been terminated; or
- Has a Capacity Agreement that is recorded on the T-4 Auction Capacity Market Register 2014 or T-4 Auction Capacity Market Register 2015 as an agreement:
- In respect of a 'new build generating CMU'

- Having more than one delivery year
- And which has not been terminated

14.15.117 The embedded export tariff will be applied to the metered Triad volumes of Grandfathered Embedded Exports for each demand zone as follows:

$$EETG_{Di} = ITT_{DiPS} + ITT_{DiYR} + GEX$$

Where

$ITT_{DiPS}$ = Peak Security Initial Transport Tariff for the demand zone;
$ITT_{DiYR}$ = Year Round Initial Transport Tariff for the demand zone, and
GEX = £45.33 in prices of first applicable charging year; indexed each year by the RPI formula set out in 14.3.6.

The Value of $EETG_{Di}$ will be floored at zero, so that $EETG_{Di}$ is always zero or positive.

**Initial Revenue Recovery**

14.15.118 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n} \left( ITT_{Gi\,PS} \times G_{Gi} \times F_{PS} \right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation
$G_{Gi}$ = Total forecast Generation for each generation zone (based on analysis of confidential User forecasts)

$F_{PS}$ = Peak Security flag appropriate to that generator type
n = Number of generation zones

The initial revenue recovery for gross GSP group demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14} \left( ITT_{DiPS} \times D_{Di} \right) = ITRR_{DPS}$$

Where:

ITRRDPS = Peak Security Initial Transport Revenue Recovery for gross GSP group demand
$D_{Di}$ = Total forecast Metered Triad gross GSP group Demand for each demand zone (based on analysis of confidential User forecasts)

14.15.119 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for Not-Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNS}\times G_{Gi}\right)=ITRR_{GYRNS}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

Where:

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.115 Similar to the Peak Security background, the initial revenue recovery for gross GSP group demand for the Year Round background is calculated by multiplying the initial tariff by the total forecast metered triad gross GSP group demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiYR}\times D_{Di}\right)=ITRR_{DYR}$$

Where:

$ITRR_{DYR}$ = Year Round Initial Transport Revenue Recovery for gross GSP group demand

14.15.120 The initial revenue recovery for Affected Embedded Exports is the Affected Embedded Export Tariff multiplied by the total forecast volume of Affected Embedded Export at triad:

$$ITRR_{EEA}=\sum_{Di=1}^{14}\left(EETA_{Di}\times EEVA_{Di}\right)$$

Where

$ITTR_{EEA}$ = Initial Revenue impact for Affected Embedded Exports

$EEVA_{Di}$ = Forecast Affected Embedded Export metered volume at Triad (MW)

For the avoidance of doubt, the initial revenue recovery for affected embedded exports can be positive or negative.

14.15.121 The initial revenue recovery for Grandfathered Embedded Exports is the Grandfathered Embedded Export Tariff multiplied by the total forecast volume of Grandfathered Embedded Export at triad:

$$ITRR_{EEG} = \sum_{Di=1}^{14}(EETG_{Di} \times EEVG_{Di})$$

Where

| | | |
|---|---|---|
| | $ITTR_{EEG}$ | = Initial Revenue impact for Grandfathered Embedded Exports |
| | $EEVG_{Di}$ | = Forecast Grandfathered Embedded Export metered volume at Triad (MW) |

For the avoidance of doubt, the initial revenue recovery for grandfathered embedded exports can be positive or negative.

**Deriving the Final Local Tariff (£/kW)**

***Local Circuit Tariff***

14.15.122 Generation with a local circuit tariff is calculated by multiplying the Year Round nodal marginal km along the local circuit by the expansion constant and the relevant local security factor (whether onshore or offshore) and summing across local circuits to give the local circuit tariff:

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$$\sum_{k} \frac{NLMkm_{Gj}{}^{L} \times EC \times LocalSF_{k}}{1000} = CLT_{Gi}$$

Where

| | | |
|---|---|---|
| $k$ | = | Local circuit $k$ for generator |
| $NLMkm_{Gj}{}^{L}$ | = | Year Round Nodal marginal km along local circuit $k$ using local circuit expansion factor. |
| EC | = | Expansion Constant |
| $LocalSF_k$ | = | Local Security Factor for circuit $k$ |
| $CLT_{Gi}$ | = | Circuit Local Tariff (£/kW) |

**Onshore Local Substation Tariff**

14.15.123 All chargeable generation is subject to the local substation tariff component which is determined by assessing the generation substation type which is the substation at the connection charging boundary, against three cost determining factors:

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(a) HV connection voltage – the voltage at the boundary between the User's connection assets and the transmission system;

(b) Sum of TEC at the generation substation – the combined TEC of all generation at the connecting substation; and

(c) The level of redundancy at the generation substation – single busbar / single switch mesh connections are examples of no redundancy connections, whereas examples of connections with redundancy include double busbar and mesh sub station designs.

14.15.124 Using the above factors, the corresponding £/kW tariffs (quoted to 3dp) that will be applied during 2010/11 are:

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| **Substation Rating** (b) | **Connection Type** (c) | **Substation Voltage** (a) | | |
|---|---|---|---|---|
| | | **132kV** | **275kV** | **400kV** |
| <1320MW | No redundancy | 0.133 | 0.081 | 0.065 |
| <1320MW | Redundancy | 0.301 | 0.192 | 0.155 |
| >=1320MW | No redundancy | n/a | 0.257 | 0.208 |
| >=1320MW | Redundancy | n/a | 0.417 | 0.336 |

14.15.125 The process for calculating Local Substation Tariffs will be carried out for the first year of the price control and will subsequently be indexed by RPI for each subsequent year of the price control period.

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14.15.126 The effective **Local Tariff** (£/kW) is calculated as the sum of the circuit and substation onshore and/or offshore components:

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$$ELT_{Gi} = CLT_{Gi} + SLT_{Gi}$$

Where
$ELT_{Gi}$ = Effective Local Tariff (£/kW)
$SLT_{Gi}$ = Substation Local Tariff (£/kW)

14.15.127 Where tariffs do not change mid way through a charging year, final local tariffs will be the same as the effective tariffs:

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$ELT_{Gi}$ = $LT_{Gi}$
Where
$LT_{Gi}$ = Final Local Tariff (£/kW)

14.15.128 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$LT_{Gi} = \frac{12 \times \left( ELT_{Gi} \times \sum_{Gi=1}^{21} G_{Gi} - FLL_{Gi} \right)}{b \times \sum_{Gi=1}^{21} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FLL = Forecast local liability incurred over the period that the original tariff is applicable for

14.15.129 For the purposes of charge setting, the total local charge revenue is calculated by:

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$$\mathrm{LCRR}_{\mathrm{G}} = \sum_{j=Gi} \mathrm{LT}_{\mathrm{Gi}} * G_j$$

Where
$LCRR_G$ = Local Charge Revenue Recovery
$G_j$ = Forecast chargeable Generation or Transmission Entry Capacity in kW (as applicable) for each generator (based on analysis of confidential information received from Users)

**Offshore substation local tariff**

14.15.130 All offshore chargeable generation is subject to an offshore substation tariff. The offshore substation tariff shall be the sum of transformer, switchgear and platform components.

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14.15.131 Each tariff component, expressed in £/kW, shall be the ratio of the Offshore Transmission Owner revenue (£) and rating associated with the transformers, switchgear or platform (kW) at each offshore substation. The Offshore Transmission Owner revenue of each tariff component shall include that associated with asset spares. In the case of the platform component, the relevant rating shall be the lower of the transformer or switchgear ratings. As with the offshore circuit expansion factors, the Offshore Transmission Owner revenue associated with each tariff component shall be averaged over the remaining years of the NETSO price control.

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14.15.132 Offshore Transmission Owner revenue associated with interest during construction and project development overheads will be attributed to the relevant asset category with which it is associated. If these or any other costs included in the Offshore Transmission Owner revenue are not readily attributable to a given asset category, they will be pro-rated across the various asset categories based on their relative cost.

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14.15.133 For 2010/11 a discount of £0.345590/kW shall be provided to the offshore substation tariff to reflect the average cost of civil engineering for onshore substations. This will be inflated by RPI each year and reviewed every price control period.

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14.15.134 Offshore substation tariffs shall be reviewed at the start of every onshore price control period. For each subsequent year within the price control period, these shall be inflated in the same manner as the associated Offshore Transmission Owner Revenue.

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14.15.135 The revenue from the offshore substation local tariff is calculated by:

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$$SLTR = \sum_{\substack{All\ offshore \\ substations}} \left( SLT_k \times \sum_k Gen_k \right)$$

Where:

| | | |
|---|---|---|
| $SLT_k$ | = | the offshore substation tariff for substation k |
| $Gen_k$ | = | the generation connected to offshore substation k |

**The Residual Tariff**

14.15.136 The total revenue to be recovered through TNUoS charges is determined each year with reference to the Transmission Licensees' Price Control formulas less the costs expected to be recovered through Pre-Vesting connection charges. Hence in any given year t, a target revenue figure for TNUoS charges ($TRR_t$) is set after adjusting for any under or over recovery for and including, the small generators discount is as follows:

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$$TRR_t = R_t - PVC_t - SG_{t-1}$$

Where

| | | |
|---|---|---|
| $TRR_t$ | = | TNUoS Revenue Recovery target for year t |
| $R_t$ | = | Forecast Revenue allowed under The Company's RPI-X Price Control Formula for year t (this term includes a number of adjustments, including for over/under recovery from the previous year). For further information, refer to Special Condition D2 of The Company's Transmission Licence. |

PVC$_t$ = Forecast Revenue from Pre-Vesting connection charges for year t

SG$_{t-1}$ = The proportion of the under/over recovery included within R$_t$ which relates to the operation of statement C13 of the The Company Transmission Licence. Should the operation of statement C13 result in an under recovery in year t – 1, the SG figure will be positive and vice versa for an over recovery.

14.15.137 In normal circumstances, the revenue forecast to be recovered from the initial transport tariffs will not equate to the total revenue target. This is due to a number of factors. For example, the transport model assumes, for simplicity, smooth incremental transmission investments can be made. In reality, transmission investment can only be made in discrete 'lumps'. The transmission system has been planned and developed over a long period of time. Forecasts and assessments used for planning purposes will not have been borne out precisely by events and therefore some distinction between an optimal system for one year and the actual system can be expected.

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14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

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$$RT_D = \frac{(p \times TRR) - ITRR_{DPS} - ITRR_{DYR} - ITRR_{EEA} - ITTR_{EEG}}{\sum_{Di=1}^{14} D_{Di}}$$

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$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

## Final £/kW Tariff

14.15.139 The effective Transmission Network Use of System tariff (TNUoS) for generation and gross demand can now be calculated as the sum of the initial transport wider tariffs for Peak Security and Year Round backgrounds, the non-locational residual tariff and the local tariff:

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$$ET_{Gi} = \frac{ITT_{GiPS} + ITT_{GiYRNS} + ITT_{GiYRS} + RT_G}{1000} + LT_{Gi}$$

$$ET_{Di} = \frac{ITT_{DiPS} + ITT_{DiYR} + RT_D}{1000}$$

Where

$ET_{Gi}$ = Effective Generation TNUoS Tariff expressed in £/kW ($ET_{Gi}$ would only be applicable to a Power Station with a PS flag of 1 and ALF of 1; in all other circumstances $ITT_{GiPS}$, $ITT_{GiYRNS}$ and $ITT_{GiYRS}$ will be applied using Power Station specific data)

$ET_{Di}$ = Effective Gross Demand TNUoS Tariff expressed in £/kW

The effective Transmission Network Use of System tariff (TNUoS) for affected embedded exports and grandfathered embedded exports can now be calculated by expressing the embedded export tariff in £/kW values:

$$ET_{EEAi} = \frac{EETA_{Di}}{1000}$$

$$ET_{EEGi} = \frac{EETG_{Di}}{1000}$$

Where

$ET_{EEAi}$ = Effective Affected Embedded Export TNUoS Tariff expressed in £/kW

$ET_{EEGi}$ = Effective Grandfathered Embedded Export TNUoS Tariff expressed in £/kW

For the purposes of the annual Statement of Use of System Charges $ET_{Gi}$ will be published as $ITT_{GiPS}$; $ITT_{GiYRNS}$, $ITT_{GiYRS}$, $RT_G$ and $LT_{Gi}$

14.15.140 Where tariffs do not change mid way through a charging year, final demand and generation tariffs will be the same as the effective tariffs.

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$$FT_{Gi} = ET_{Gi}$$

$$FT_{Di} = ET_{Di}$$

$$FT_{EEAi} = ET_{EEAi}$$

$$FT_{EEGi} = ET_{EEGi}$$

14.15.141 Where tariffs are changed part way through the year, the final tariffs will be calculated by scaling the effective tariffs to reflect that the tariffs are only applicable for part of the year and parties may have already incurred TNUoS liability.

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$$FT_{Gi} = \frac{12 \times \left( ET_{Gi} \times \sum_{Gi=1}^{20} G_{Gi} - FL_{Gi} \right)}{b \times \sum_{Gi=1}^{27} G_{Gi}} \quad \text{and} \quad FT_{Di} = \frac{12 \times \left( ET_{Di} \times \sum_{Di=1}^{14} D_{Di} - FL_{Di} \right)}{b \times \sum_{Di=1}^{14} D_{Di}}$$

$$FT_{EEAi} = \frac{12 \times (ET_{EEAi} \times \sum_{Di=1}^{14} EETA_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETA_{Di}} \quad \text{and} \quad FT_{EEGi} = \frac{12 \times (ET_{EEGi} \times \sum_{Di=1}^{14} EETG_{Di} - FL_{Di})}{b \times \sum_{Di=1}^{14} EETG_{Di}}$$

Where:
b = number of months the revised tariff is applicable for
FL = Forecast liability incurred over the period that the original tariff is applicable for

Note: The $ET_{Gi}$ element used in the formula above will be based on an individual Power Stations PS flag and ALF for Power Station $G_{Gi}$, aggregated to ensure overall correct revenue recovery.

14.15.142 If the final gross demand TNUoS Tariff results in a negative number then this is collared to £0/kW with the resultant non-recovered revenue smeared over the remaining demand zones:

If $FT_{Di} < 0$, then $i$ = 1 to z

Therefore, $$NRRT_D = \frac{\sum_{i=1}^{z}(FT_{Di} \times D_{Di})}{\sum_{i=z+1}^{14} D_{Di}}$$

Therefore the revised Final Tariff for the gross demand zones with positive Final tariffs is given by:

For $i$= 1 to z: $RFT_{Di} = 0$

For $i$=z+1 to 14: $RFT_{Di} = FT_{Di} + NRRT_D$

Where

$NRRT_D$ = Non Recovered Revenue Tariff (£/kW)

$RFT_{Di}$ = Revised Final Tariff (£/kW)

14.15.143 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges,** which is available from the **Charging website.** Archived tariff information may also be obtained from the Charging website**.**

14.15.144 The zonal maps referenced in The Company's **Statement of Use of System Charges** and available on the **Charging website** contain detailed information for the charging year in question of which Grid Supply Points fall into which TNUoS zones.

14.15.145 New Grid Supply Points will be classified into zones on the following basis:

- For demand zones, according to the GSP Group to which the Grid Supply Point is allocated for energy market settlement purposes.

- For generation zones, with reference to the geographic proximity to existing zones and, where close to a boundary between existing zones, with reference to the marginal costs arising from transport model studies. The GSP will then be allocated to the zone, which contains the most similar marginal costs.

14.15.146 The Company has available, upon request, the DCLF ICRP transport model, tariff model template and data necessary to run the model, consisting of nodal values of generation and demand connection points to the NETS. The model and data will enable the basic nodal charges to be determined and will also allow sensitivity analysis concerning alternative developments of generation and demand to be undertaken. The model is available from the Charging Team and whilst it is free of charge, it is provided under licence to restrict its distribution and commercial use.

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14.15.147 The Company will be pleased to run specific sensitivity studies for Users under a separate study contract in line with the fees set out in the **Statement of Use of System Charges**. Please contact the **Charging Team**.

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14.15.148 The factors which will affect the level of TNUoS charges from year to year include-;

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- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.
- changes in the pattern of embedded exports

14.15.149 In accordance with Standard Licence Condition C13, generation directly connected to the NETS 132kV transmission network which would normally be subject to generation TNUoS charges but would not, on the basis of generating capacity, be liable for charges if it were connected to a licensed distribution network qualifies for a reduction in transmission charges by a designated sum, determined by the Authority. Any shortfall in recovery will result in a unit amount increase in gross demand charges to compensate for the deficit. Further information is provided in the Statement of the Use of System Charges.

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### Stability & Predictability of TNUoS tariffs

14.15.150 A number of provisions are included within the methodology to promote the stability and predictability of TNUoS tariffs. These are described in 14.29.

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## 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW Gross Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

**£/kW Tariff** = The £/kW Effective Gross Demand Tariff (£/kW), as calculated previously**,** for the GSP Group concerned.

**$NHHD_F$** = The Company's forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

**$FL_G$** = Forecast Liability incurred for the GSP Group concerned.

**$NHHC_G$** = The Company's forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

### Short Term Transmission Entry Capacity (STTEC) Tariff

14.16.3 The Short Term Transmission Entry Capacity (STTEC) tariff for positive zones is derived from the Effective Tariff ($ET_{Gi}$) annual TNUoS £/kW tariffs (14.15.112). If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the STTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (i.e. over the whole financial year, not just the period that the STTEC is applicable for). STTECs will not be reconciled following a mid year charge change. The premium associated with the flexible product is associated with the analysis that 90% of the annual charge is linked to the system peak. The system peak is likely to occur in the period of November to February inclusive (120 days, irrespective of leap years). The calculation for positive generation zones is as follows:

$$\frac{FT_{Gi} \times 0.9 \times STTEC\ Period}{120} = \text{STTEC tariff (£/kW/period)}$$

Where:

| | | |
|---|---|---|
| FT | = | Final annual TNUoS Tariff expressed in £/kW |
| Gi | = | Generation zone |
| STTEC Period | = | A period applied for in days as defined in the CUSC |

14.16.4 For the avoidance of doubt, the charge calculated under 14.16.3 above will represent each single period application for STTEC. Requests for multiple /STTEC periods will result in each STTEC period being calculated and invoiced separately.

14.16.5 The STTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

## Limited Duration Transmission Entry Capacity (LDTEC) Tariffs

14.16.6 The Limited Duration Transmission Entry Capacity (LDTEC) tariff for positive zones is derived from the equivalent zonal STTEC tariff for up to the initial 17 weeks of LDTEC in a given charging year (whether consecutive or not). For the remaining weeks of the year, the LDTEC tariff is set to collect the balance of the annual TNUoS liability over the maximum duration of LDTEC that can be granted in a single application. If multiple set of tariffs are applicable within a single charging year, the Final Tariff used in the LDTEC calculation will be prorated in an identical manner to that used when calculating a generators annual liability. The periods over which the tariff would be prorated would be identical to the periods used when calculating the wider tariff (ie over the whole financial year, not just the period that the STTEC is applicable for). LDTECs will not be reconciled following a mid year charge change:

Initial 17 weeks (high rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.9 \times 7}{120}$$

Remaining weeks (low rate):

$$\text{LDTEC tariff (£/kW/week)} = \frac{FT_{Gi} \times 0.1075 \times 7}{316 - 120} \times (1 + P)$$

where *FT* is the final annual TNUoS tariff expressed in £/kW;
$G_i$ is the generation TNUoS zone; and
*P* is the premium in % above the annual equivalent TNUoS charge as determined by The Company, which shall have the value 0.

14.16.7 The LDTEC tariff for generators with negative final tariffs is set to zero to prevent Users receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

14.16.8 The tariffs applicable for any particular year are detailed in The Company's **Statement of Use of System Charges** which is available from the **Charging website.** Historical tariffs are also available on the **Charging website.**

# 14.17 Demand Charges

## Parties Liable for Demand Charges

14.17.1 Demand charges are subdivided into charges for gross demand, energy and embedded export. The following parties shall be liable for some or all of the categories of demand charges:

- The Lead Party of a Supplier BM Unit;
- Power Stations with a Bilateral Connection Agreement;
- Parties with a Bilateral Embedded Generation Agreement

14.17.2 Classification of parties for charging purposes, section 14.26, provides an illustration of how a party is classified in the context of Use of System charging and refers to the paragraphs most pertinent to each party.

## Basis of Gross Demand Charges

14.17.3 Gross demand charges are based on a de-minimis £0/kW charge for Half Hourly and £0/kWh for Non Half Hourly metered demand.

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14.17.4 Chargeable Gross Demand Capacity is the value of Triad gross demand (kW). Chargeable Energy Capacity is the energy consumption (kWh). The definition of both these terms is set out below.

14.17.5 If there is a single set of gross demand tariffs within a charging year, the Chargeable Gross Demand Capacity is multiplied by the relevant gross demand tariff, for the calculation of gross demand charges.

14.17.6 If there is a single set of energy tariffs within a charging year, the Chargeable Energy Capacity is multiplied by the relevant energy consumption tariff for the calculation of energy charges..

14.17.7 If multiple sets of gross demand tariffs are applicable within a single charging year, gross demand charges will be calculated by multiplying the Chargeable Gross Demand Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

$$Annual\ Liability_{Demand} = \frac{Chargeable\ Gross}{Demand\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

Deleted: $Annual\ Liability_{D}$

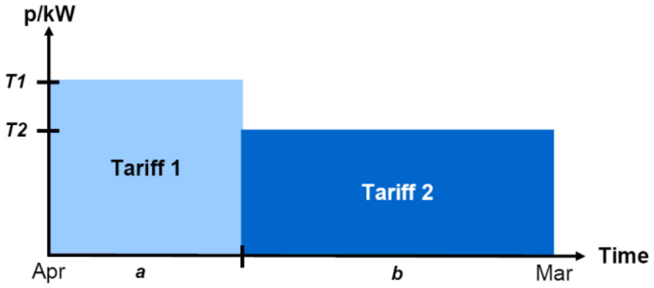
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




14.17.8 If multiple sets of energy tariffs are applicable within a single charging year, energy charges will be calculated by multiplying relevant Tariffs by the Chargeable Energy Capacity over the period that that the tariffs are applicable for and summing over the year.

$$Annual\ Liability_{Energy} = Tariff\ 1 \times \sum_{T1_S}^{T1_E} Chargeable\ Energy\ Capacity$$
$$+ Tariff\ 2 \times \sum_{T2_S}^{T1_E} Chargeable\ Energy\ Capacity$$

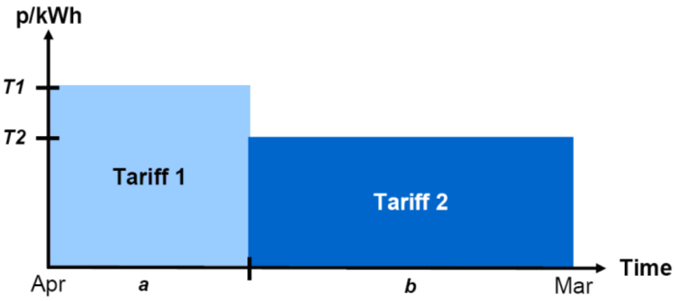
Where:

$T1_S$ = Start date for the period for which the original tariff is applicable,

$T1_E$ = End date for the period for which the original tariff is applicable,

$T2_S$ = Start date for the period for which the revised tariff is applicable,

$T2_E$ = End date for the period for which the revised tariff is applicable.




## Basis of Embedded Export Charges

14.17.9 Embedded export charges are based on a £/kW charge for Half Hourly metered embedded export.

14.17.10 Chargeable Embedded Export Capacity is the value of Embedded Export at Triad (kW). The definition of this term is set out below.

If there is a single set of embedded export tariffs within a charging year, the Chargeable Embedded Export Capacity is multiplied by the relevant embedded export tariff, for the calculation of embedded export charges.

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14.17.12 If multiple sets of embedded export tariffs are applicable within a single charging year, embedded export charges will be calculated by multiplying the Chargeable Embedded Export Capacity by the relevant tariffs pro rated across the months that they are applicable for, as below,

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$$Annual\ Liability_{Demand} = \frac{Chargeable\ Embedded}{Export\ Capacity} \times \left(\frac{(a \times Tariff\ 1) + (b \times Tariff\ 2)}{12}\right)$$

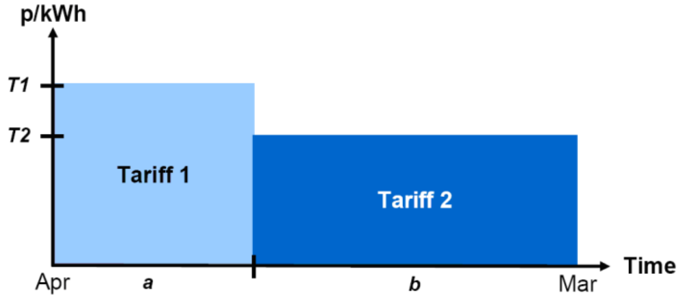
where:

Tariff 1 = Original tariff,

Tariff 2 = Revised tariff,

a = Number of months over which the original tariff is applicable,

b = Number of months over which the revised tariff is applicable.




**Supplier BM Unit**

14.17.13 A Supplier BM Unit charges will be the sum of its energy, gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity will be the average of the Supplier BM Unit's half-hourly metered gross demand during the Triad (and the £/kW tariff),
- The Chargeable Embedded Export Capacity will be the average of the Supplier BM Unit's half-hourly metered embedded export during the Triad (and the £/kW tariff), *and*
- The Chargeable Energy Capacity will be the Supplier BM Unit's non half-hourly metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year (and the p/kWh tariff).

**Power Stations with a Bilateral Connection Agreement and Licensable Generation with a Bilateral Embedded Generation Agreement**

14.17.14 The Chargeable Gross Demand Capacity for a Power Station with a Bilateral Connection Agreement or Licensable Generation with a Bilateral Embedded Generation Agreement will be based on the average of the gross import over each Triad leg of the BM Units associated with the Power Station (in Appendix C of its Bilateral Connection Agreement or Bilateral Embedded Generation Agreement, including metered additional load) during the Triad.

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**Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement**

14.17.15 The demand charges for Exemptible Generation and Derogated Distribution Interconnector with a Bilateral Embedded Generation Agreement will be the sum of its gross demand and embedded export liabilities where:

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- The Chargeable Gross Demand Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered gross demand of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

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- The Chargeable Embedded Export Capacity for Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement will be based on the average of the metered embedded export of each BM Unit specified in Appendix C of the Bilateral Embedded Generation Agreement during the Triad.

## Small Generators Tariffs

14.17.16 In accordance with Standard Licence Condition C13, any under recovery from the MAR arising from the small generators discount will result in a unit amount of increase to all GB gross demand tariffs.

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## The Triad

14.17.17 The Triad is used as a short hand way to describe the three settlement periods of highest transmission system demand within a Financial Year, namely the half hour settlement period of system peak net demand and the two half hour settlement periods of next highest net demand, which are separated from the system peak net demand and from each other by at least 10 Clear Days, between November and February of the Financial Year inclusive. Exports on directly connected Interconnectors and Interconnectors capable of exporting more than 100MW to the Total System shall be excluded when determining the system peak net demand. An illustration is shown below.

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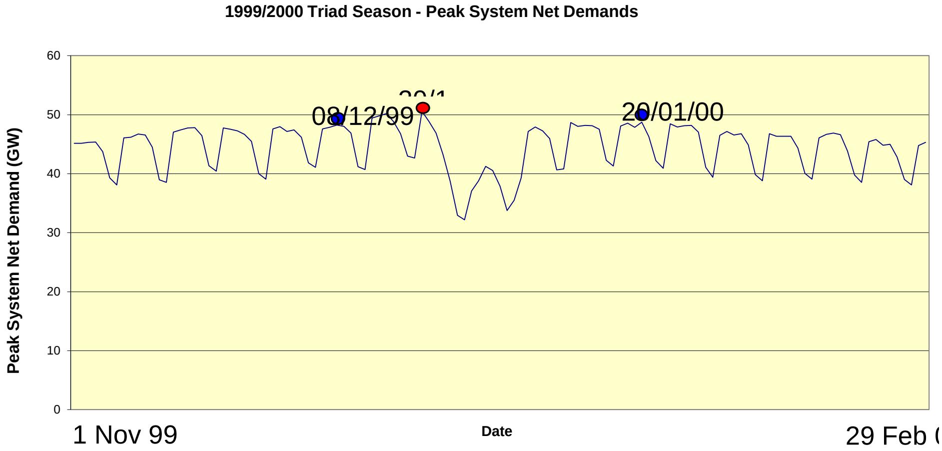


**Half-hourly metered demand charges**

14.17.18 For Supplier BMUs and BM Units associated with Exemptible Generation and Derogated Distribution Interconnectors with a Bilateral Embedded Generation Agreement, if the average half-hourly metered gross demand volume over the Triad results in an import, the Chargeable Gross Demand Capacity will be positive resulting in the BMU being charged.
If the average half-hourly metered embedded export volume over the Triad results in an export, the Chargeable Embedded Export Capacity will be negative resulting in the BMU being paid the relevant tariff; where the tariff is positive. For the avoidance of doubt, parties with Bilateral Embedded Generation Agreements that are liable for Generation charges will not be eligible for payment of the embedded export tariff.

**Monthly Charges**

14.17.19 Throughout the year Users will submit a Demand Forecast. A Demand Forecast will include:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit
- half-hourly metered embedded export to be exported during the Triad for each BM Unit
- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit

14.17.20 Throughout the year Users' monthly demand charges will be based on their Demand Forecast of:

- half-hourly metered gross demand to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

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14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based.¶

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- half-hourly metered embedded export to be supplied during the Triad for each BM Unit, multiplied by the relevant zonal £/kW tariff; and

- non-half hourly metered energy to be supplied over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year for each BM Unit, multiplied by the relevant zonal p/kWh tariff

Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year. Users have the opportunity to vary their demand forecasts on a quarterly basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. Users will be notified of the timescales and process for each of the quarterly updates. The Company will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months. For the avoidance of doubt, only positive demand forecasts (i.e. representing a net import from the system) will be used in the calculation of charges.

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Demand forecasts for a User will be considered positive where:

- The sum of the gross demand forecast and embedded export forecast is positive; and
- The non-half hourly metered energy forecast is positive.

14.17.21 Users should submit reasonable forecasts of gross demand, embedded export and energy in accordance with the CUSC. The Company shall use the following methodology to derive a forecast to be used in determining whether a User's forecast is reasonable, in accordance with the CUSC, and this will be used as a replacement forecast if the User's total forecast is deemed unreasonable. The Company will, at all times, use the latest available Settlement data.

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For existing Users:

i) The User's Triad gross demand and embedded export for the preceding Financial Year will be used where User settlement data is available and where The Company calculates its forecast before the Financial Year. Otherwise, the User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export in the Financial Year to date is compared to the equivalent average gross demand and embedded export for the corresponding days in the preceding year. The percentage difference is then applied to the User's HH gross demand and embedded export at Triad in the preceding Financial Year to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

ii) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day in the Financial Year to date is compared to the equivalent energy consumption over the corresponding days in the preceding year. The percentage difference is then applied to the User's total NHH energy consumption in the preceding Financial Year to derive a forecast of the User's NHH energy consumption for this Financial Year.

For new Users who have completed a Use of System Supply Confirmation Notice in the current Financial Year:

iii) The User's average weekday settlement period 35 half-hourly metered (HH) gross demand and embedded export over the last complete month for which The Company has settlement data is calculated. Total system average HH gross demand and embedded export for weekday settlement period 35 for the corresponding month in the previous year is compared to total system HH gross demand and embedded export at Triad in that year and a percentage difference is calculated. This percentage is then applied to the User's average HH gross demand and embedded export for weekday settlement period 35 over the last month to derive a forecast of the User's HH gross demand and embedded export at Triad for this Financial Year.

iv) The User's non half-hourly metered (NHH) energy consumption over the period 16:00 hrs to 19:00 hrs every day over the last complete month for which The Company has settlement data is noted. Total system NHH energy consumption over the corresponding month in the previous year is compared to total system NHH energy consumption over the remaining months of that Financial Year and a percentage difference is calculated. This percentage is then applied to the User's NHH energy consumption over the month described above, and all NHH energy consumption in previous months is added, in order to derive a forecast of the User's NHH metered energy consumption for this Financial Year.

14.17.22 14.28 Determination of The Company's Forecast for Demand Charge Purposes illustrates how the demand forecast will be calculated by The Company.

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## Reconciliation of Demand Charges

14.17.23 The reconciliation process is set out in the CUSC. The demand reconciliation process compares the monthly charges paid by Users against actual outturn charges. Due to the Settlements process, reconciliation of demand charges is carried out in two stages; initial reconciliation and final reconciliation.

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### Initial Reconciliation of demand charges

14.17.24 The initial reconciliation process compares Users' demand forecasts and corresponding monthly charges paid over the year against actual outturn data (using latest Settlement data available at the time) and corresponding charges. Initial reconciliation is carried out in two parts; Initial Reconciliation Part 1 deals with the reconciliation of half-hourly metered demand charges and Initial Reconciliation Part 2 deals with the reconciliation of non-half-hourly metered demand charges.

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### Initial Reconciliation Part 1– Half-hourly metered demand

14.17.25 The Company will identify the periods forming the Triad once it has received Central Volume Allocation data from the Settlement Administration Agent for all days up to and including the last day of February. Once The Company has notified Users of the periods forming the Triad they will not be changed even if disputes are subsequently resolved which would change the periods forming the Triad.

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14.17.26 Initial outturn charges for half-hourly metered gross demand will be determined using the latest available data of actual average Triad gross demand (kW) multiplied by the zonal gross demand tariff(s) (£/kW) applicable to the months

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concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly gross demand.

14.17.27 Initial outturn charges for half-hourly metered embedded export will be determined using the latest available data of actual average Triad embedded export (kW) multiplied by the zonal embedded export tariff(s) (£/kW) applicable to the months concerned for each zone for that Financial Year. These actual values are then reconciled against the monthly charges paid in respect of half-hourly embedded exports.

**Initial Reconciliation Part 2 – Non-half-hourly metered demand**

14.17.28 Actual payments for non-half-hourly metered demand will be determined using the latest available actual energy consumption data (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) over the year multiplied by the energy consumption tariff(s) (p/kWh) applicable to the months concerned for each zone. These actual values are then reconciled against the monthly charges paid in respect of non-half-hourly energy consumption.

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**Final Reconciliation of demand charges**

14.17.29 The final reconciliation process compares Users' charges (as calculated during the initial reconciliation process using the latest available data) against final outturn demand charges (based on final settlement data of half-hourly gross demand, embedded exports and non-half-hourly energy consumption).

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14.17.30 Final actual charges will be determined using the final demand reconciliation data taken from the Final Reconciliation Settlement Run or the Final Reconciliation Volume Allocation Run.

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**Reconciliation of manifest errors**

14.17.31 In the event that a manifest error, or multiple errors in the calculation of TNUoS tariffs results in a material discrepancy in aUsers TNUoS tariff, the reconciliation process for all Users qualifying under Section 14.17.33 will be in accordance with Sections 14.17.24 to 14.17.50. The reconciliation process shall be carried out using recalculated TNUoS tariffs. Where such reconciliation is not practicable, a post-year reconciliation will be undertaken in the form of a one-off payment.

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14.17.32 A manifest error shall be defined as any of the following:

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a) an error in the transfer of relevant data between the Transmission Licensees or Distribution Network Operators;
b) an error in the population of the Transport Model with relevant data;
c) an error in the function of the Transport Model; or
d) an error in the inputs or function of the Tariff Model.

14.17.33 A manifest error shall be considered material in the event that such an error or, the net effect of multiple errors, has an impact of the lesser of either:

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a) an error in a User's TNUoS tariff of at least +/-£0.50/kW; or

b) an error in a User's TNUoS tariff which results in an error in the annual TNUoS charge of a User in excess of +/-£250,000.

14.17.34 A manifest error shall only be reconciled if it has been identified within the charging year for which the error has an effect. Errors identified outside of this period will not be eligible for reconciliation retrospectively.

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**Implementation of P272**

14.17.35.1 BSC modification P272 requires Suppliers to move Profile Classes 5-8 to Measurement Class E - G (i.e. moving from NHH to HH settlement) by April 2016. The majority of these meters are expected to transfer during the preceding Charging Years up until the implementation date of P272 and some meters will have been transferred before the start of 1ST April 2015. A change from NHH to HH within a Charging Year would normally result in Suppliers being liable for TNUoS for part of the year as NHH and also being subject to HH charging. This section describes how the Company will treat this situation in the transition to P272 implementation for the purposes of TNUoS charging; and the forecasts that Suppliers should provide to the Company.

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14.17.35.2 Notwithstanding 14.17.13, for each Charging Year which begins after 31 March 2015 and prior to implementation of BSC Modification P272, all demand associated with meters that are in NHH Profile Classes 5 to 8 at the start of that charging year as well as all meters in Measurement Classes E G will be treated as Chargeable Energy Capacity (NHH) for the purposes of TNUoS charging for the full Charging Year unless 14.17.35.3 applies.

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14.17.35.3 Where prior to 1st April 2015 a Profile Class meter has already transferred to Measurement Class settlement (HH) the associated Supplier may opt to treat the demand volume as Chargeable Demand Capacity (HH) for the purposes of TNUoS charging up until implementation of P272, subject to meeting conditions in 14.17.35.6. If the associated Supplier does not opt to treat the demand volume as Demand Capacity (HH) it will be treated by default as Chargeable Energy Capacity (NHH) for each full Charging Year up until implementation of P272.

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14.17.35.4 The Company will calculate the Chargeable Energy Capacity associated with meters that have transferred to HH settlement but are still treated as NHH for the purposes of TNUoS charging from Settlement data provided directly from Elexon i.e. Suppliers need not Supply any additional information if they accept this default position.

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14.17.35.5 The forecasts that Suppliers submit to the Company under CUSC 3.10, 3.11 and 3.12 for the purpose of TNUoS monthly billing referred to in 14.17.20 and 14.17.21 for both Chargeable Demand Capacity and Chargeable Energy Capacity should reflect this position i.e. volumes associated those Metering Systems that have transferred from a Profile Class to a Measurement Class in the BSC (NHH to HH settlement) but are to be treated as NHH for the purposes of TNUoS charging should be included in the forecast of Chargeable Energy Capacity and not Chargeable Demand Capacity, unless 14.17.35.3 applies.

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14.17.35.6 Where a Supplier wishes for Metering Systems that have transferred from Profile Class to Measurement Class in the BSC (NHH to HH settlement) prior to 1st April 2015, to be treated as Chargeable Demand Capacity (HH/

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Measurement Class settled) it must inform the Company prior to October 2015. The Company will treat these as Chargeable Demand Capacity (HH / Measurement Class settled) for the purposes of calculating the actual annual liability for the Charging Years up until implementation of P272. For these cases only, the Supplier should notify the Company of the Meter Point Administration Number(s) (MPAN). For these notified meters the Supplier shall provide the Company with verified metered demand data for the hours between 4pm and 7pm of each day of each Charging Year up to implementation of P272 and for each Triad half hour as notified by the Company prior to May of the following Charging Year up until two years after the implementation of P272 to allow reconciliation (e.g. May 2017 and May 2018 for the Charging Year 2016/17). Where the Supplier fails to provide the data or the data is incomplete for a Charging Year TNUoS charges for that MPAN will be reconciled as part of the Supplier's NHH BMU (Chargeable Energy Capacity). Where a Supplier opts, if eligible, for TNUoS liability to be calculated on Chargeable Demand Capacity it shall submit the forecasts referred to in 14.17.35.5 taking account of this.

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14.17.35.7 The Company will maintain a list of all MPANs that Suppliers have elected to be treated as HH. This list will be updated monthly and will be provided to registered Suppliers upon request.

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## Further Information

14.17.36 14.25 Reconciliation of Demand Related Transmission Network Use of System Charges of this statement illustrates how the monthly charges are reconciled against the actual values for gross demand, embedded export and consumption for half-hourly gross demand, embedded export and non-half-hourly metered demand respectively.

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14.17.37 **The Statement of Use of System Charges** contains the £/kW zonal gross demand tariffs, the £/kW zonal embedded export tariffs, and the p/kWh energy consumption tariffs for the current Financial Year.

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14.17.38 14.27 Transmission Network Use of System Charging Flowcharts of this statement contains flowcharts demonstrating the calculation of these charges for those parties liable.

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## 14.24 Example: Calculation of Zonal Gross Demand Tariff

Let us consider all nodes in a demand zone in this example

The table below shows a sample output of the transport model comprising the node, the Peak Security and Year Round marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national net demand and the net demand sited at the node.

| Demand Zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) |
|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 |
| 14 | EXET40 | -87.69 | -164.42 | 340 |
| 14 | HINP20 | -46.55 | -147.14 | 0 |
| 14 | HINP40 | -46.55 | -147.14 | 0 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 |
| 14 | LAND40 | -62.54 | -246.16 | 262 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 |
| | | **Totals** | | **2748** |

In order to calculate the gross demand tariff we would carry out the following steps:

(i) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

| Demand zone | Node | Peak Security Nodal Marginal km | Year Round Nodal Marginal km | Net Demand (MW) | Peak Security Demand Weighted Nodal Marginal km | Year Round Demand Weighted Nodal Marginal km |
|---|---|---|---|---|---|---|
| 14 | ABHA4A | -77.25 | -230.25 | 127 | -3.57 | -10.64 |
| 14 | ABHA4B | -77.27 | -230.12 | 127 | -3.57 | -10.64 |
| 14 | ALVE4A | -82.28 | -197.18 | 100 | -2.99 | -7.17 |
| 14 | ALVE4B | -82.28 | -197.15 | 100 | -2.99 | -7.17 |
| 14 | AXMI40_SWEB | -125.58 | -176.19 | 97 | -4.43 | -6.22 |
| 14 | BRWA2A | -46.55 | -182.68 | 96 | -1.63 | -6.38 |
| 14 | BRWA2B | -46.55 | -181.12 | 96 | -1.63 | -6.33 |
| 14 | EXET40 | -87.69 | -164.42 | 340 | -10.85 | -20.34 |
| 14 | INDQ40 | -102.02 | -262.50 | 444 | -16.48 | -42.41 |
| 14 | IROA20_SWEB | -109.05 | -141.92 | 462 | -18.33 | -23.86 |
| 14 | LAND40 | -62.54 | -246.16 | 262 | -5.96 | -23.47 |
| 14 | MELK40_SWEB | 18.67 | -140.75 | 83 | 0.56 | -4.25 |
| 14 | SEAB40 | 65.33 | -140.97 | 304 | 7.23 | -15.59 |
| 14 | TAUN4A | -66.65 | -149.11 | 55 | -1.33 | -2.98 |
| 14 | TAUN4B | -66.66 | -149.11 | 55 | -1.33 | -2.98 |
| | | **Totals** | | **2748** | **-49.19** | **-190.43** |

(ii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 49.19km for Peak Security background and 190.43km for Year Round background.

(iii) calculate the transport tariffs by multiplying the figures in (ii) above by the expansion constant (& dividing by 1000 to put into units of £/kW):

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

$$\frac{49.19\text{km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£0.89/kW}}$$

b) Year Round tariff -

$$\frac{190.43km * £10.07/MWkm * 1.8}{1000} = \underline{\textbf{£3.45/kW}}$$

(iv) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year), less the revenue which would be recovered through the demand transport tariffs and revenue recovery through embedded export tariffs, divided by total expected gross GSP group demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from gross GSP group demand would be (73% x £1067m) = £779m. Assuming the total recovery from gross GSP group demand transport tariffs is £140m, total recovery from embedded export tariffs is -£10m and total forecast chargeable gross GSP group demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{£779m - £140m - -£10m}{50{,}000MW} = £12.98/kW$$

(v) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 14:

£0.89/kW + £3.45/kW + £12.98/kW = **£17.32/kW**

To summarise, in order to calculate the gross demand tariffs, we evaluate a net demand weighted zonal marginal km cost multiply by the expansion constant and locational security factor then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW gross demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final gross demand tariff.

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¶

£779m - £140m - -£10m = £12.98/kW¶

50,000MW

## 14.25 Reconciliation of Gross Demand Related Transmission Network Use of System Charges

This appendix illustrates the methodology used by The Company in the reconciliation of Transmission Network Use of System charges for gross demand. The example highlights the different stages of the calculations from the monthly invoiced amounts, right through to Final Reconciliation.

### Monthly Charges

Suppliers provide half-hourly (HH) gross demand and embedded export forecasts and non-half-hourly (NHH) demand forecasts by BM Unit every quarter. An example of such forecasts and the corresponding monthly invoiced amounts, based on tariffs of £10.00/kW for gross demand, £5.00/kW for embedded export and 1.20p/kWh for energy consumption, is as follows:

| | Forecast HH Triad Gross Demand $HHD_F$ (kW) | HH Gross Demand Monthly Invoiced Amount (£) | Forecast HH Triad Embedded Export $HHEE_F$ (kW) | HH Embedded Generation Monthly Invoiced Amount (£) | Forecast NHH Energy Consumption $NHHC_F$(kWh) | NHH Monthly Invoiced Amount (£) | Net Monthly Invoiced Amount (£) |
|---|---|---|---|---|---|---|---|
| Apr | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| May | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jun | 12,000 | 10,000 | -600 | (250) | 15,000,000 | 15,000 | 24,750 |
| Jul | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Aug | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Sep | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Oct | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Nov | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Dec | 12,000 | 10,000 | -600 | (250) | 18,000,000 | 19,000 | 28,750 |
| Jan | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Feb | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Mar | 7,200 | (6,000) | -600 | (250) | 18,000,000 | 19,000 | 12,750 |
| Total | | 72,000 | | (3,000) | | 216,000 | 297,000 |

As shown, for the first nine months the Supplier provided a 12,000kW HH triad gross demand forecast, and hence paid HH gross demand monthly charges of £10,000 ((12,000kW x £10.00/kW)/12) for that BM Unit. In January the Supplier provided a revised forecast of 7,200kW, implying a forecast annual charge reduced to £72,000 (7,200kW x £10.00/kW). The Supplier had already paid £90,000, so the excess of £18,000 was credited back to the supplier in three £6,000 instalments over the last three months of the year.

The Supplier provided an embedded export triad forecast of -600kW and hence was paid an embedded export credit of £250 ((600kW x £5.00/kW)/12) for that BM Unit (For the avoidance of doubt, if the embedded export tariff is negative this will result in a debit).

The Supplier also initially provided a 15,000,000kWh NHH energy consumption forecast, and hence paid NHH monthly charges of £15,000 ((15,000,000kWh x 1.2p/kWh)/12) for that BM Unit. In July the Supplier provided a revised forecast of 18,000,000kWh, implying a forecast annual charge increased to £216,000 (18,000,000kWh x 1.2p/kWh). The Supplier had already

paid £45,000, so the remaining £171,000 was split into payments of £19,000 for the last nine months of the year.

The right hand column shows the net monthly charges for the BM Unit.

### Initial Reconciliation (Part 1a)

The Supplier's outturn HH triad gross demand, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 9,000kW. The HH triad gross demand reconciliation charge is therefore calculated as follows:

HHD Reconciliation Charge = $(HHD_A - HHD_F)$ x £/kW Tariff

= (9,000kW - 7,200kW) x £10.00/kW

= 1,800kW x £10.00/kW

**= £18,000**

To calculate monthly interest charges, the outturn HHD charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHD charge less the HH gross demand monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

### Initial Reconciliation (Part 1b)

The Supplier's outturn HH triad embedded export, based on initial settlement data (and therefore subject to change in subsequent settlement runs), was 700kW. The HH triad embedded export reconciliation charge is therefore calculated as follows:

HHEE Reconciliation Charge = $(HHEE_A – HHEE_F)$ x £/kW Tariff

= (-500kW - -600kW) x £5.00/kW

= 100kW x £5.00/kW

= **£500**

To calculate monthly interest charges, the outturn HHEE charge is split equally over the 12-month period. The monthly reconciliation amount is the monthly outturn HHEE charge less the HH embedded generation monthly invoiced amount. Interest payments are calculated based on these monthly reconciliation amounts using Barclays Base Rate.

**Deleted:** Please note that payments made to BM Units with a net export over the Triad, based on initial settlement data, will also be reconciled at this stage.¶
As monthly payments will not be made on the basis of a negative forecast, the HHD Reconciliation Charge for an exporting BM Unit will represent the full actual payment owed to that BM Unit (subject to adjustment by subsequent settlement runs). Interest will be calculated as described above.¶

### Initial Reconciliation (Part 2)

The Supplier's outturn NHH energy consumption, based on initial settlement data, was 17,000,000kWh. The NHH energy consumption reconciliation charge is therefore calculated as follows:

NHHC Reconciliation Charge = $\frac{(NHHC_A - NHHC_F) \times p/kWh\ Tariff}{100}$

= $\frac{(17{,}000{,}000kWh - 18{,}000{,}000kWh) \times 1.20p/kWh}{100}$

= $\frac{-1{,}000{,}000kWh \times 1.20p/kWh}{100}$

worked example 4.xls - Initial!J104 **= -£12,000**

The monthly reconciliation amount is equal to the outturn energy consumption charge for that month less the NHH monthly invoiced amount. Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

The net initial TNUoS demand reconciliation charge is therefore £6,500 (£18,000 +£500 - £12,000).

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### Final Reconciliation

Finally, let us now suppose that after all final Settlement data has been received (up to 14 months after the relevant dates), the outturn HH triad gross demand, HH triad embedded export and NHH energy consumption values were 9,500kW, -550kW and 16,500,000kWh, respectively.

Final HH Gross Demand Reconciliation Charge = (9,500kW - 9,000kW) x £10.00/kW
= £5,000

Final HH Embedded Export Reconciliation Charge = (-550kW - -500kW) x £5.00/kW
= -£250

Final NHH Reconciliation Charge = $\frac{(16{,}700{,}000kWh – 17{,}000{,}000kWh) \times 1.20p/kWh}{100}$
= -£3,600

Consequently, the net final TNUoS demand reconciliation charge will be £1,150 (£5,000 + -£250 + -£3,600).

Interest payments are calculated based on the monthly reconciliation amounts using Barclays Base Rate.

Outturn data for BM Units with a net export over the Triad will be received at this stage and final reconciliation will be carried out, as required. Interest will be calculated as described above.

**Terminology:**

**$HHD_A$** = The Supplier's outturn half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHD_F}$ = The Supplier's forecast half-hourly metered Triad Gross Demand (kW) for the demand zone concerned.

$\mathbf{HHEE_A}$ = The Supplier's outturn half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{HHEE_F}$ = The Supplier's forecast half-hourly metered Triad Embedded Export (kW) for the demand zone concerned.

$\mathbf{NHHC_A}$ = The Supplier's outturn non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

$\mathbf{NHHC_F}$ = The Supplier's forecast non-half-hourly metered daily Energy Consumption (kWh) for the period 16:00 hrs to 19:00 hrs inclusive (i.e. settlement periods 33 to 38) from April 1$^{st}$ to March 31$^{st}$, for the demand zone concerned.

**£/kW Tariff** = The £/kW Gross Demand or Embedded Export Tariff as shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

**p/kWh Tariff** = The Energy Consumption Tariff shown in Schedule 1 of **The Statement of Use of System Charges** for the demand zone concerned.

## 14.26 Classification of parties for charging purposes

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precendence.

In the following diagrams, the parties liable for Transmission Network Use of System charges are outlined in red.

| **SUPPLIER** | |
|---|---|
| **Supplier Use of System Agreement**<br>**Supplier** BMU1 ..... Supplier **BMUn** | |
| Demand Charges<br>See **14.17.13 and 14.17.18.** | Generation Charges<br>None. |

| **POWER STATION WITH A BILATERAL CONNECTION AGREEMENT** | |
|---|---|
| **Bilateral Connection Agreement Appendix C**<br>**Gen Unit** BMU1 ..... Gen Unit **BMUn** · **Station Load BMU** · **Additional Load BMU** | |
| Demand Charges<br>See **14.17.14.** | Generation Charges<br>See **14.18.1 i) and 14.18.3 to 14.18.9 and 14.18.18.**<br>For generators in positive zones, see **14.18.10 to 14.18.12.**<br>For generators in negative zones, see **14.18.13 to 14.18.17.** |

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<table>
<tr><td colspan="2">PARTY WITH A BILATERAL EMBEDDED GENERATION AGREEMENT</td></tr>
<tr><td colspan="2">Bilateral Embedded Generation Agreement Appendix C<br>Gen Unit BMU1 | Gen Unit BMUn | Station Load BMU | Additional Load BMU</td></tr>
<tr><td>Demand Charges<br><br>See 14.17.14, 14.17.15 and 14.17.18.</td><td>Generation Charges<br><br>See 14.18.1 ii).<br><br>For generators in positive zones, see 14.18.3 to 14.18.12 and 14.18.18.<br><br>For generators in negative zones, see 14.18.3 to 14.18.9 and 14.18.13 to 14.18.18.</td></tr>
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## 14.27 Transmission Network Use of System Charging Flowcharts

The following flowcharts illustrate the parties liable for Demand and Generation TNUoS charges and the calculation of those charges.

In the event of any conflict between this Appendix and the main text within this Statement, the main text within the Statement shall take precedence.

### Demand Charges

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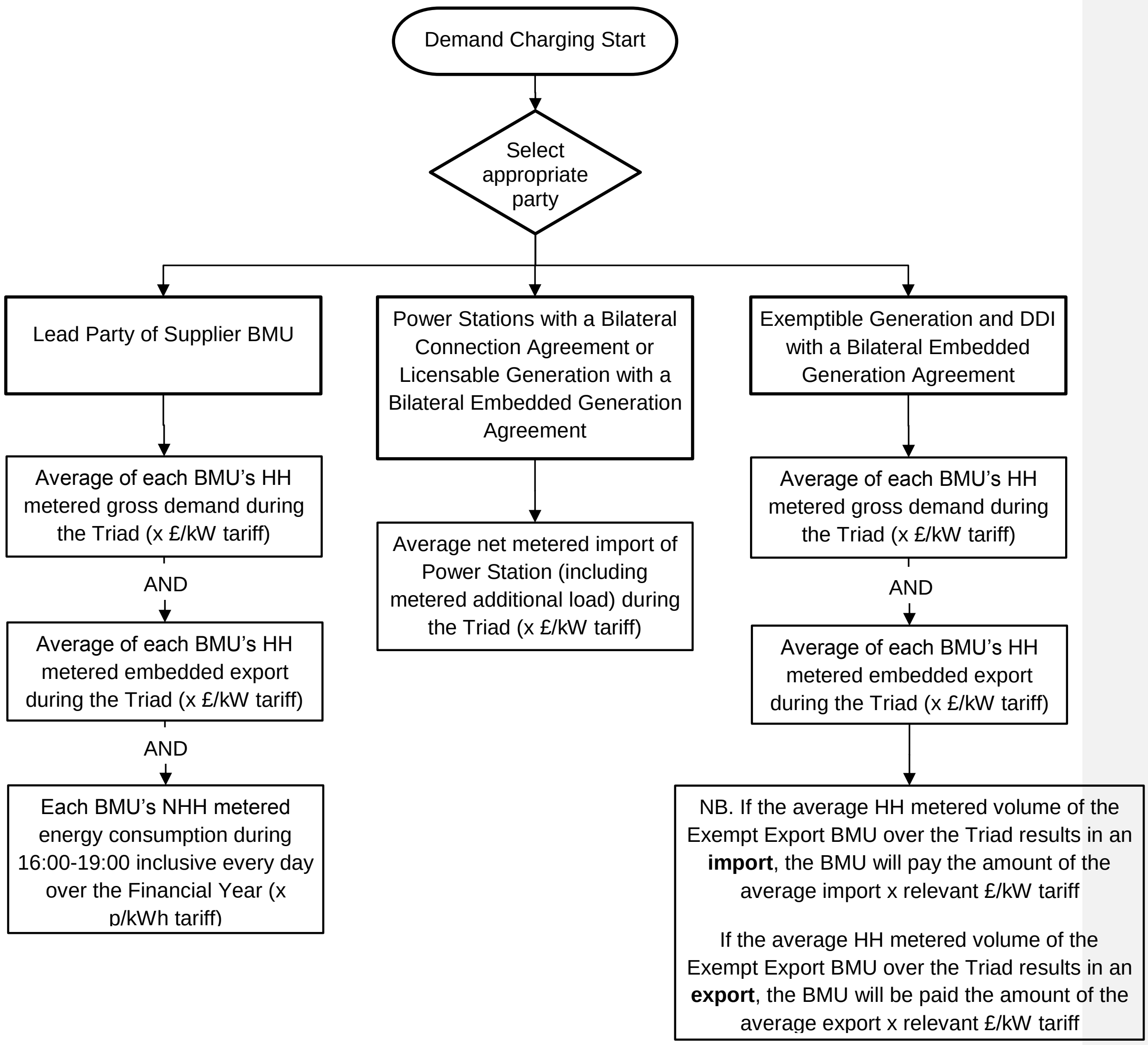
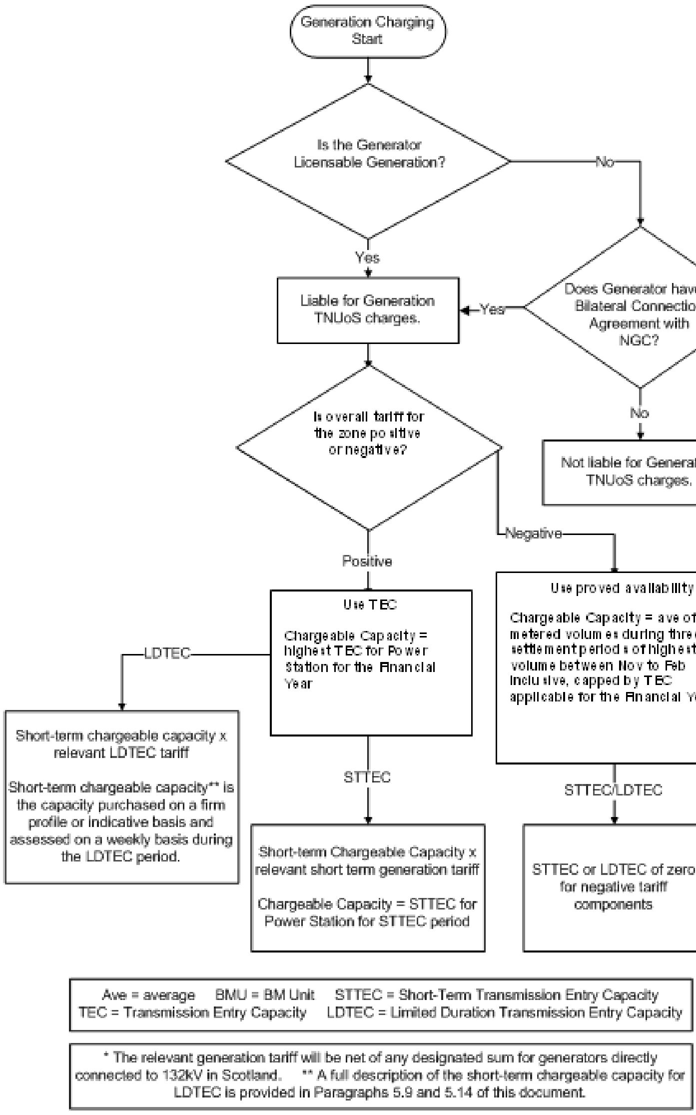



BMU = BM Unit    DDI = Derogated Distribution Interconnector
HH = Half hourly    NHH = Non-half hourly

Generation
Charges



## 14.28 Example: Determination of The Company's Forecast for Demand Charge Purposes

The Company will use the latest available settlement data for calculation of HH demand and NHH energy consumption forecasts for the Financial Year.

The Financial Year runs from 1st April to 31st March inclusive and for the purpose of these examples the year April 2005 to March 2006 is used.

Where the preceding year's settlement data is not available at the time that The Company needs to calculate its forecast, The Company will use settlement data from the corresponding period in Financial Year minus two unless indicated otherwise.

All values used with the examples are purely for illustrative purposes only.

### i) Half-Hourly (HH) Metered Demand Forecast – Existing User

At the time of calculation of a HH demand forecast before the relevant Financial Year (approximately 10th March), The Company will be aware at a system level which dates will be used for the determination of Triad. However, The Company may not have settlement data at a User level if the Triad dates were to span a period that includes the latter half of February.

When undertaking forecasting before the relevant Financial Year, The Company will use the User's Triad demand for the previous year for its forecast providing it holds User settlement data for this period, thus:

F = T

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in Financial Year minus one

Where The Company determines its forecast within a Financial Year:

F = T * D/P

where:

F = Forecast of User's HH demand at Triad for the Financial Year

T = User's HH gross demand and embedded export at Triad in the preceding Financial Year

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the preceding Financial Year

Where The Company determines its forecast before the relevant Financial Year and User settlement data for the Triad period is not available, The Company shall apply the formula immediately above (within year forecast) but substitute the following definitions for the values T, D, and P:

T = User's HH gross demand and embedded export at Triad in the Financial Year minus two

D = User's average half hourly metered gross demand and embedded export in settlement period 35 in the Financial Year minus one, to date

P = User's average half hourly metered gross demand and embedded export in settlement period 35 for the period corresponding to D in the Financial Year minus two

**Example** (where User settlement data is not yet available for the Triad period):

The Company calculates a HH demand forecast on the above methodology at 10th March 2005 for the period 1st April 2005 to 31st March 2006.

Gross demand:

F = 10,000 * 13,200 / 12,000

F = 11,000 kW

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where:

T = 10,000 kW (period November 2003 to February 2004)

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D = 13,200 kW (period 1st April 2004 to 15th February 2005#)

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P = 12,000 kW (period 1st April 2003 to 15th February 2004)

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# Latest date for which settlement data is available.

Embedded export:

F = -280 * -300 / -350

F = -240 kW

where:

T = -280 kW (period November 2003 to February 2004)

D = -300 kW (period 1st April 2004 to 15th February 2005#)

P = -350 kW (period 1st April 2003 to 15th February 2004)

# Latest date for which settlement data is available.

### ii) Non Half-Hourly (NHH) Metered Energy Consumption Forecast – Existing User

F = E * D/P

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

E = User's summed NHH energy consumption over the hours 16:00 to 19:00 for each day in the preceding Financial Year

D = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the Financial Year to date

P = User's summed NHH energy consumption for the hours 16:00 to 19:00 for each day for the period corresponding to D in the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10th June 2005 for the period 1st April 2005 to 31st March 2006.

F = 50,000,000 * 4,400,000 / 4,000,000

F = 55,000,000 kWh

where:

E = 50,000,000 kWh (period 1st April 2004 to 31st March 2005)

D = 4,400,000 kWh (period 1st April 2005 to 15th May 2005#)

P = 4,000,000 kWh (period 1st April 2004 to 15th May 2004)

# Latest date for which settlement data is available

Where forecasting before the relevant Financial Year concerned, The Company would in the above example use values for E and P from Financial Year 2003/04 and D from Financial Year 2004/05.

**iii) Half-Hourly (HH) Metered Demand Forecast – New User**

F = M * T/W

where:

F = Forecast of User's HH metered gross demand and embedded export at Triad for the Financial Year

M = User's HH average weekday period 35 demand for the last complete month for which settlement data is available

T = Total system HH gross demand and embedded export at Triad in the preceding Financial Year

W = Total system HH average weekday settlement period 35 metered demand for the corresponding period to M for the preceding year

**Example:**

The Company calculates a HH demand forecast on the above methodology at 10th September 2005 for a new User registered from 10th June 2005 for the period 10th June 2004 to 31st March 2006.

Gross demand:

F = 1,000 * 17,000,000 / 18,888,888

F = 900 kW

where:

M = 1,000 kW (period 1st July 2005 to 31st July 2005)

T = 17,000,000 kW (period November 2004 to February 2005)

W = 18,888,888 kW (period 1st July 2004 to 31st July 2004)

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Embedded export:

F = 150 * 7,200,000 / 6,000,000

F = 180 kW

where:

M = 150 kW (period 1st July 2005 to 31st July 2005)

T = 7,200,000 kW (period November 2004 to February 2005)

W = 6,000,000 kW (period 1st July 2004 to 31st July 2004)

**iv) Non Half Hourly (NHH) Metered Energy Consumption Forecast – New User**

F = J + (M * R/W)

where:

F = Forecast of User's NHH metered energy consumption for the Financial Year

J = Residual part month summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day where new User registration takes place other than on the first of a month

M = User's summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the last complete month for which settlement data is available

R = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period from the start of that defined under M but for the preceding year and until the end of that preceding Financial Year

W = Total system summed NHH metered energy consumption for the hours 16:00 to 19:00 for each day for the period identified in M but for the preceding Financial Year

**Example:**

The Company calculates a NHH energy consumption forecast on the above methodology at 10$^{th}$ September 2005 for a new User registered from 10$^{th}$ June 2005 for the period 10$^{th}$ June 2005 to 31$^{st}$ March 2006.

F = 500 + (1,000 * 20,000,000,000 / 2,000,000,000)

F = 10,500 kWh

where:

J = 500 kWh (period 10$^{th}$ June 2005 to 30$^{th}$ June 2005)

M = 1,000 kWh (period 1$^{st}$ July 2005 to 31$^{st}$ July 2005)

R = 20,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ March 2005)

W = 2,000,000,000 kWh (period 1$^{st}$ July 2004 to 31$^{st}$ July 2004)

## CMP 269 & 270

| | |
|---|---|
| **"CUSC Party"** | as defined in the **Transmission Licence**; |
| **"Customer"** | a person to whom electrical power is provided (whether or not he is the provider of such electrical power) other than power to meet **Station Demand** of that person; |
| **"Customer Services Team"** | the customer services team identified within **The Company** which manages the commercial interface with parties connected to the transmission network, as identified on the **Website**; |
| **"DC Converter"** | As defined in the **Grid Code**; |
| **"Data Registration Code" or "DRC"** | the portion of the **Grid Code** which is identified as the **Data Registration Code**; |
| **"DCLF"** | Direct Current Load Flow; |
| **"Deemed HH Forecasting Performance"** | the sum calculated in accordance with Section 3, Appendix 2 Paragraph 3 as it may be revised in accordance with paragraph 3.22.7. |
| **"Deemed NHH Forecasting Performance"** | the sum calculated in accordance with Section 3, Appendix 2 Paragraph 6 as it may be revised pursuant to Paragraph 3.22.8. |
| **"Deenergisation" or "Deenergise(d)"** | the movement of any isolator, breaker or switch or the removal of any fuse whereby no electricity can flow to or from the relevant **System** through the **User's Equipment**; |
| **"Defaulting Party"** | as defined in Paragraph 4.3.2.11; |
| **"Defendant Party"** | as defined in Paragraph 7.5.1; |
| **"Delivering"** | as defined in the **Balancing and Settlement Code**; |
| **"De-Load"** | the difference (expressed in MW) between the **Maximum Export Limit** and the **Final Physical Notification Data** as adjusted by the **Acceptance Volume** in respect of a **Bid-Offer Acceptance** (if any), and "**De-Loaded**" shall be construed accordingly; |
| **"Demand"** | the demand of MW and Mvar of electricity (i.e. both **Active Power** and **Reactive Power**), unless otherwise stated; |
| **"Demand Forecast"** | a **User's** forecast, in accordance with paragraph 14.17.19, of its **Demand** submitted to **The Company** in accordance with paragraphs 3.10, 3.11 and 3.12; |
| **"Depreciation Period"** | in relation to a **Transmission Connection Asset** for a particular **User**, the period which commences on the asset's initial effective charging date, and which expires after the appropriate duration, |

which unless otherwise agreed upon connection is 40 years excluding FMS metering electronics that are agreed between the **User** and **The Company**;