nationalgrid

Stage 04: Code Administrator Consultation

Connection and Use of System Code (CUSC)

CMP214 Implementation of TNUoS Charging Parameter Updates following a Price Control Review

What stage is this document at?

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

This proposal seeks to modify the CUSC to alter the implementation of any required updates to those TNUoS charging parameters reviewed at the start of a price control period, including generation charging zones, to the start of the second charging year within the new price control period.

Published on: **05 November 2012**
Length of Consultation: **10 Working Days**
Responses by: **19 November 2012**

National Grid opinion:
CMP214 should be implemented as it better facilitates Applicable CUSC Objective (a) through providing longer term visibility of changes to TNUoS tariffs which will improve the predictability of TNUoS charges and participants' ability to efficiently commercially manage changes.

High Impact:
All parties who pay TNUoS charges.

Contents

About this document

The purpose of this document is to consult on CMP214 with CUSC Parties and other interested industry members. Representations received in response to this consultation document will be included in National Grid's CUSC Modification Report that will be furnished to the Authority for their determination.

Document Control

Version	Date	Author	Change Reference
1.0	19 November 2012	Code Administrator	Version to the Industry

Any Questions?

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1 Summary

1.1 This document describes the CMP214 Modification Proposal and seeks views from industry members relating to the proposal.

1.2 CMP214 seeks to alter the implementation date for any updates to the charging parameters used in the calculation of Transmission Use of System (TNUoS) tariffs which are reviewed at the start of each price control period. This includes updates to generation charging zones.

1.3 CMP214 was proposed by National Grid Electricity Transmission Plc and submitted to the CUSC Modifications Panel for their consideration on 25 October 2012. Further to the Proposer's recommendation that CMP214 should be progressed through the urgent route, the Panel determined that the proposal should be progressed as urgent on the basis that CMP214 is an imminent issue and can have a significant impact. The Authority accepted the Panel's recommendation to progress CMP214 as Urgent. Further details on CMP214 and its treatment as urgent can be found in section 1.7.

1.4 The Panel determined that CMP214 should be sent to the Code Administrator Consultation phase for a period of 10 working days and that a Special Panel meeting would be held on 27 November 2012 for the Panel Recommendation Vote. The proposed timetable is contained as Annex 3.

1.5 This Code Administrator Consultation has been prepared in accordance with the Terms of the CUSC. An electronic copy can be found on the National Grid Website, www.nationalgrid.com/uk/Electricity/Codes/ along with the CUSC Modification Proposal Form.

What is TNUoS?

Transmission Network Use of System Charges recover the costs incurred by Transmission Owners in their businesses. They reflect the costs of installing and maintaining the National Electricity Transmission System assets required to allow the transfer of power between connection sites and to provide transmission security. Zonal tariffs are produced annually by National Grid.

National Grid's View

1.6 National Grid supports the implementation of CMP214 as it better facilitates Applicable CUSC Objective (a) in that it will improve efficient competition in the generation and supply of electricity. This is through longer-term visibility of changes to TNUoS charging parameters and generation charging zones which will assist the predictability of TNUoS charges allowing suppliers and generators to efficiently incorporate these charges into their overall pricing structures. The Proposer's justification for urgency can be found within the CUSC Modification Proposal Form in Annex 1.

Urgency Criteria

1.7 The CUSC Panel considered the Proposer's request for urgency with reference to Ofgem's guidance on Code Modification Urgency Criteria.[1] The majority view of the Panel was that CMP214 should be treated as Urgent for the following reasons:

(i) CMP214 refers to an imminent issue, in that the CUSC requires final 2013/14 tariffs to be published by the end of January 2013 and that it is standard practice to publish draft tariffs before the end of December; and

(ii) The issues addressed by CMP214 may cause a significant impact on the TNUoS charges that generators and suppliers are liable for.

[1] Ofgem's Urgency Criteria can be found here: http://www.ofgem.gov.uk/Licensing/IndCodes/Governance/Documents1/Ofgem%20Guidance%20on%20Code%20Modification%20Urgency%20Criteria.pdf

1.8 The CUSC Panel Chairman wrote to the Authority on 29 October 2012 with the request for CMP214 to be treated as an urgent proposal. This letter can be found in Annex 4. The Authority approved the request on 01 November 2012, and a copy of their approval letter can be found in Annex 5.

2 Why Change?

2.1 TNUoS tariffs are comprised of two separate elements. Firstly, a locational element which reflects the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element relating to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

2.2 A number of parameters used to derive the locational element of generation and demand TNUoS tariffs are fixed or are limited to inflationary updates between price control reviews. The purpose of this is to provide stability of tariffs. At the start of each new price control period these charging parameters are reviewed and updated. The review includes a number of key elements as listed below.

- the expansion constant and expansion factors, which reflect the cost of investing in the transmission network;
- the charging parameters used in the calculation of the expansion constant and expansion factors, namely the annuity factor (comprised of the weighted average cost of capital, and asset life), the overhead factor (the cost of operating and maintaining the transmission system), and capital costs (the cost of capital investment on the transmission system);
- the locational security factor that reflects the cost of providing a secure integrated transmission network; and
- the generation charging zone boundaries.

2.3 These key elements, their role in the setting of TNUoS tariffs, and their impact on TNUoS tariffs are further described in Annex 7.

2.4 Due to the time between each price control period, when reviewed there can be significant changes to some or all of these key elements, which in turn can have a significant impact on the TNUoS charges which generators and suppliers are liable for.

2.5 Changes to some or all of these key elements can affect both wider and local TNUoS tariffs paid by generation users, and also zonal demand and energy consumption tariffs paid by demand users.

2.6 As part of National Grid's RIIO-T1 stakeholder engagement, National Grid discussed transmission charges with customers, and found that they value charges which are transparent, predictable, and where possible stable, although predictability is paramount. Additionally, Ofgem stated in their recent consultation[2] that network charging volatility arising from the price control is one of the key issues raised by stakeholders during the current price control reviews.

2.7 The review of charging parameters and generation zones is dependent on information from two main sources. The first of these is network data such as information relating to the National Electricity Transmission System as well as generation and demand backgrounds. This is not confirmed until the end of October ahead of the start of the new price control period. The second information source is financial data which cannot be confirmed until

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[2] Mitigating network charging volatility arising from the price control settlement

the final proposals for the new price control are announced, which for RIIO-T1 is expected to be in mid-December 2012. Table 1 below indicates the dependencies of the charging parameters on these two data sources.

	Network Data Dependent	Financial Data Dependent
Expansion Constant	No	Yes
Expansion Factors	No	Yes
Security Factor	Yes	No
Generator Zones	Yes	Yes

Table 1 – Data dependencies of charging parameters

2.8 The timeline for the review of charging parameters and generation charging zones for the start of RIIO-T1 is described further in Annex 6.

2.9 Additionally, the review of the generation charging zone boundaries is dependent on having first finalised any updates to the charging parameters including the expansion constant, expansion factors and locational security factor.

2.10 Whilst National Grid can begin to analyse the likely impact of any charging parameter changes ahead of this data being confirmed, the full impact on TNUoS tariffs and generation charging zones cannot be understood and communicated in draft form to customers until at least late December prior to the start of the new price control period. This is three months before the start of the new charging year when these changes would be implemented.

2.11 National Grid therefore believe that, if the changes to these charging parameters and/or generation charging zones are found to cause significant change to TNUoS tariffs, coupled with the provision of only three months notice of the change, this will introduce a significant level of unpredictability to TNUoS charges.

2.12 The RIIO-T1 price control period is expected to commence in April 2013. National Grid have therefore commenced the required review of charging parameters and generation charging zones, and have presented their initial analysis of likely changes and their potential impact on TNUoS tariffs to industry at the September 2012 Transmission Charging Methodologies Forum (TCMF). This analysis, presented in Annex 6 of this report, shows potential for significant change to TNUoS tariffs. Under the current methodology these changes would take effect from 1 April 2013.

2.13 National Grid believes, based on engagement with stakeholders through both TCMF and its RIIO-T1 stakeholder engagement, that the effect of these changes are not predictable to TNUoS charge payers until the outcome of the review and update of charging parameters and generation charging zones is known. Therefore, under the current TNUoS charging methodology, any required changes cannot be efficiently incorporated into generator and supplier pricing structures.

3 Solution

3.1 This CUSC modification proposal seeks to delay the implementation of any required updates to those charging parameters and generation charging zones reviewed by the start of a new price control period until the start of the second charging year within the new price control period. For example, changes to charging parameters or generation charging zones for the RIIO-T1 price control period (commencing in April 2013) would not take effect until 1 April 2014.

3.2 This will provide customers with additional notice of all charging parameter changes reviewed by the start of a new price control period and generation charging zone changes, thus improving the predictability of TNUoS charges, and allowing them to efficiently incorporate the changes into their pricing structures.

3.3 It is proposed that the publication of revised charging parameters and generation charging zones would continue to be by the start of the price control period.

3.4 For the avoidance of doubt, this proposal is limited to those charging parameters which are reviewed at the start of a new price control period, including the review of generation charging zones which is dependent on the outcome of the charging parameter review. In the first year of the price control parameters would be updated by RPI as they are during price control periods.

3.5 In addition to the need for the review of generation charging zones at the start of a new price control period, paragraph 14.15.21 of Section 14 of the CUSC, describes the potential need for review and update of these zones in “exceptional circumstances” during a price control period. This proposal seeks to treat such generation charging zone reviews and updates in an identical manner to those undertaken at the start of a price control period.

3.6 This proposal seeks to modify the timing of changes which affect the locational element of TNUoS tariffs only. Hence there is no proposed change to the TNUoS charging methodology for calculation of the residual element, and therefore there is no impact on the collection of Transmission Owner allowed revenue.

3.7 It is acknowledged that, for a one year period, there will be a slight reduction in the cost reflectivity of TNUoS charges as a result of this proposal. However the proposer believes that this is justified because the benefits to end consumers from increased predictability of TNUoS charges outweigh this temporary reduction for the following reasons;

- TNUoS charges provide a long term locational signal to customers of the cost of transmission. Therefore a one year delay to input parameter changes should not affect the long term behaviour of a user provided the changes are forecast and predictable.

- It is acknowledged in the TNUoS charging methodology (paragraph 14.28) that, to assist the stability of TNUoS charges under the existing arrangements, certain charging parameters and generation charging zones remain fixed, or have limited updates, during a price control period (other than in exceptional circumstances). This results in a loss of cost reflectivity for the period of the price control. This is significantly greater loss than that which would be introduced through this proposal.

4 Impacts

Impact on the CUSC

4.1 CMP214 requires amendments to the following parts of the CUSC:

- Section 14 Part 2

4.2 The text required to give effect to this proposal is contained in Annex 2 of this document.

Impact on Greenhouse Gas Emissions

4.3 The proposer has not identified any material impacts on Greenhouse gas Emissions

Impact on Core Industry Documents

4.4 The proposer has not identified any impacts on Core Industry Documents.

Impact on other Industry Documents

4.5 The proposer has not identified any impacts on other Industry Documents.

5 Proposed Implementation

5.1 National Grid proposes that CMP214 is implemented the next working day after an Authority decision. In accordance with 8.22.10 (b) of the CUSC, **views are invited on this proposed implementation date**.

6 The Case for Change

Assessment against Applicable CUSC Objectives

6.1 For reference, the Applicable CUSC Objectives are:

Use of System Charging Methodology

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

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

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

6.2 The proposer considers that CMP214 would better facilitate the following CUSC Objective:

(a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; in that it allows suppliers and generators to have sufficient view of upcoming changes to enable them to incorporate those changes into their pricing structure (i.e. to provide transparent and predictable charges).

7 How to Respond

7.1 If you wish to make a representation on this Code Administrator Consultation, please use the response proforma which can be found under CMP214 at the following link:

http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

7.2 Views are invited to the following questions:

1. Do you believe that CMP214 better facilitates the Applicable CUSC Objectives as set out in paragraph 6.1?

2. Do you support the proposed implementation approach?

3. Do you believe that the current methodology (i.e. potential changes to TNUoS charging parameters and generation charging zones in late December to take effect in charges from the following April) allows for changes associated with a price control review to be efficiently incorporated into supplier and generator pricing structures?

4. Do you believe that the proposal will significantly affect the predictability of TNUoS charges?

5. Do you agreed that the suggested trade-off between cost reflectivity of TNUoS charges from a one year delay of implementation of changes to the charging parameters reviewed by the start of a price control period and generation charging zones is outweighed by the benefit in competition through increased predictability of the charges?

6. Do you believe that the agreed timetable will facilitate the intended benefits of the proposal?

7. Can you provide any evidence on the ability of suppliers or generators to predict the outcome of the review of TNUoS charging parameters and generation charging zones associated with a price control review?

8. Do you have any other evidence or comments that you believe may assist in the assessment of this proposal?

7.3 Views are invited upon the proposals outlined in this consultation, which should be received by **19 November 2012.**

Your formal responses may be emailed to:

cusc.team@nationalgrid.com

7.4 If you wish to submit a confidential response please note the following:

Information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response marked "Private and Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the CUSC Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non confidential response.

Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential".

CUSC Modification Proposal Form (for Charging Methodology proposals)	CMP214

Title of the CUSC Modification Proposal: *(mandatory by proposer)*

Implementation of TNUoS charging parameter updates following a price control review

Submission Date *(mandatory by Proposer)*

25th October 2012

Description of the CUSC Modification Proposal: *(mandatory by proposer)*

There are a number of charging parameters used in the calculation of TNUoS tariffs which are reviewed and, if required, updated at the start of each price control period. This proposal seeks to alter the implementation date for any updates to these parameters to the start of the charging year after the commencement of a new price control period. For example, changes to parameters for the RIIO-T1 price control period (commencing in April 2013) will not take effect until 1st April 2014.

It is proposed that the publication of revised parameters would continue to be by the start of the price control period, i.e. unchanged from the current CUSC baseline.

For the avoidance of doubt, this proposal is limited to those charging parameters which are reviewed at the start of a new price control period, including the review of generation zones which is dependent on the outcome of the charging parameter review.

Description of Issue or Defect that the CUSC Modification Proposal seeks to Address: *(mandatory by proposer)*

A number of parameters used to derive the locational component of generation and demand TNUoS tariffs are fixed or have inflationary updates between price control reviews. The purpose of this is to provide stability and predictability of tariffs. At the start of each new price control period these charging parameters must be reviewed and updated. The scope of the review includes:

- the expansion constant and expansion factors, which reflect the cost of investing in the transmission network;
- the charging parameters making up the expansion constant, namely the annuity factor (comprised of the weighted average cost of capital, and asset life), the overhead factor, and the capital costs;
- the locational security factor that reflects the cost of an integrated transmission network; and
- the generation charging zone boundaries which is dependent on the outcome of the charging parameter review.

Given the time that elapses between price control reviews (eight years going forwards), there are likely to be significant changes to at least some of the input parameters, which can have a significant impact on TNUoS charges paid by generators and suppliers. In the case of the RIIO-T1 price control review, the potential impact on charges is illustrated in Annex 1.

The review of these charging parameters is dependent on two data sources;

1. network data, such as information to allow review of expansion factors as well as generation and demand backgrounds. Expansion factor information from external transmission owners is only finalised from the October ahead of the start of the new price control period.

2. financial information from the price control such as efficiency assumptions, operating costs, and the cost of capital. This can only be confirmed once final proposals for the RIIO-T1 price controls are announced. In the case of RIIO-T1 for NGET these are anticipated in mid-December, approximately 15 weeks before the proposed start of the new price control period.

The following table indicates the dependencies of the charging parameters on these two data sources.

	Network Data Dependent	Financial Data Dependent
Expansion Constant	No	Yes
Expansion Factors	No	Yes
Security Factor	Yes	No
Generator Zones	Yes	Yes

Additionally, the review of the generation charging zone boundaries is dependent on having first finalised any update to charging parameters including the expansion constant, expansion factors and locational security factor.

In summary, the full impact on TNUoS tariffs and generation charging zones cannot be understood and communicated in draft form to customers until at least late December prior to the start of the new price control period. This is only three months before the start of the new charging year when it is required these changes to be implemented to TNUoS charges.

Paragraph 14.14.10 of Section 14 of the CUSC requires that National Grid publish final TNUoS tariffs by the end of January prior to the new charging year. Whilst the above timeline allows these tariffs to be produced, it also presents a potentially considerable amount of volatility to TNUoS tariffs only three months ahead of their introduction.

In the case of RIIO-T1, this potential volatility, including possible changes to the composition of generation charging zones, was presented to industry at the September Transmission Charging Methodologies Forum (TCMF) and is attached for reference in Annex 1 of this proposal.

The purpose of this CUSC modification proposal is to reduce this potential volatility in TNUoS charges through delay to the implementation of any required changes to charging parameters until the start of the charging year after the commencement of a new price control period. This will provide customers with additional notice of any parameter changes, improving the predictability of TNUoS charges, and allowing them to efficiently incorporate the changes into their pricing structures.

Impact on the CUSC: *(this should be given where possible)*

Changes would be limited to Section 14 Part 2 of the CUSC to clarify, for each affected input parameter, the timescale for review, publication and implementation. It is proposed that this could be efficiently discharged through reference to new common paragraphs within Section 14 to explicitly state that;

- Charging parameters will be reviewed and published prior to the start of the new price control period.
- Implementation of any required changes will take place <u>at the start of the charging year after the commencement of a new price control period.</u>

Do you believe the CUSC Modification Proposal will have a material impact on Greenhouse Gas Emissions? Yes/No *(mandatory by Proposer. Assessed in accordance with Authority Guidance – see guidance notes for website link)*

No

Impact on Core Industry Documentation. Please tick the relevant boxes and provide any supporting information: *(this should be given where possible)*

BSC ☐

Grid Code ☐

STC ☐

Other ☐

(please specify)

None

Urgency Recommended: Yes / No *(optional by Proposer)*

Yes

Justification for Urgency Recommendation *(mandatory by Proposer if recommending progression as an Urgent Modification Proposal)*

The RIIO-T1 price control is due to be implemented for Transmission Owners from April 2013. Compliance with the current CUSC baseline would require charging parameters to be reviewed and updated in the TNUoS methodology ahead of this date with final information to undertake analysis not available until December 2012. Hence we believe that the review and update of these charging parameters;

- is an **imminent issue** as, in accordance with the CUSC, final tariffs need to be notified by 31st January 2013 and custom and practice is that draft tariffs are published before Christmas. Our proposed timetable has been attached to this submission.;
- and can have a **significant impact** on parties, as the changes could be large in magnitude and would be implemented at short notice because of the dependency of these on the outcome of the price control.

Self-Governance Recommended: Yes / No *(mandatory by Proposer)*

No

Justification for Self-Governance Recommendation *(mandatory by Proposer if recommending progression as Self-governance Modification Proposal)*

Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews? *(mandatory by Proposer in order to assist the Panel in deciding whether a Modification Proposal should undergo a SCR Suitability Assessment)*

There are no ongoing Significant Code Reviews affecting this proposal.

Impact on Computer Systems and Processes used by CUSC Parties: *(this should be given where possible)*

None

Details of any Related Modifications to Other Industry Codes (including related CUSC Modification Proposals): *(where known)*

None

Justification for CUSC Modification Proposal with reference to Applicable CUSC Objectives: ***(mandatory by proposer)***

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

Use of System Charging Methodology

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

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

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

Full justification:

As part of our RIIO-T1 stakeholder engagement we have discussed transmission charges with customers, and have found that customers value charges which are transparent, predictable, and where possible stable, although predictability is paramount. In addition, Ofgem have stated in their recent consultation[3] that network charging volatility arising from the price control is one of the key issues raised by stakeholders during the current price control reviews.

On this basis, we believe that there is a strong case for implementing TNUoS changes associated with a price control in a manner which allows customers to have sufficient view to enable them to incorporate those changes into their pricing structure (i.e. to provide transparent and predictable charges). We believe that this will help facilitate competition in the electricity market by allowing suppliers and generators to efficiently incorporate transmission charges into their overall pricing structure.

Whilst we believe that, for a one year period, there will be a slight reduction in the cost reflectivity of TNUoS charges as a result of this proposal we believe that this is outweighed by the benefits for competition. Additionally, TNUoS charges provide a long term locational signal to customers of the cost of transmission. Therefore a one year delay to input parameter changes should not affect the long term behaviour of a user provided the changes are forecast and predictable.

Connection Charging Methodology

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

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

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

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

Full justification:

[3] Mitigating network charging volatility arising from the price control settlement

Details of Proposer: (Organisation's Name)	National Grid
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party, "National Consumer Council" or Materially Affected Party)	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	**Andy Wainwright** **National Grid** **01926 655944** **Andy.wainwright@nationalgrid.com**
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Adelle McGill National Grid 01926 653142 Adelle.mcgill@nationalgrid.com
Attachments (Yes/No): Yes **If Yes, Title and No. of pages of each Attachment: Annex 1 – Latest National Grid view on potential changes to the TNUoS charging parameters and their potential impact[4] (3 pages)** Microsoft Word Document Microsoft PowerPoint Presentation [5]	

[4] http://www.nationalgrid.com/NR/rdonlyres/AA5C22F4-204B-4EA1-9818-264E7B8209CF/57224/NGviewonchangingparameters.pdf

[5] http://www.nationalgrid.com/NR/rdonlyres/F6AC0487-FB53-4025-8D42-BD3F71B76D7F/57225/CMP214potentialtimetable.pdf

14.14.5 In April 2004 The Company introduced a DC Loadflow (DCLF) ICRP based transport model for the England and Wales charging methodology. The DCLF model has been extended to incorporate Scottish network data with existing England and Wales network data to form the GB network in the model. In April 2005, the GB charging methodology implemented the following proposals:

i.) The application of multi-voltage circuit expansion factors with a forward-looking Expansion Constant that does not include substation costs in its derivation.

ii.) The application of locational security costs, by applying a multiplier to the Expansion Constant reflecting the difference in cost incurred on a secure network as opposed to an unsecured network.

iii.) The application of a de-minimus level demand charge of £0/kW for Half Hourly and £0/kWh for Non Half Hourly metered demand to avoid the introduction of negative demand tariffs.

iv.) The application of 132kV expansion factor on a Transmission Owner basis reflecting the regional variations in network upgrade plans.

v.) The application of a Transmission Network Use of System Revenue split between generation and demand of 27% and 73% respectively.

vi.) The number of generation zones using the criteria outlined in paragraph 14.15.2~~6~~7 has been determined as 21.

vii.) The number of demand zones has been determined as 14, corresponding to the 14 GSP groups.

14.15 Derivation of the Transmission Network Use of System Tariff

14.15.4 A number of charging parameters that are inputs to the TNUoS methodology are fixed, or have limited updates, for the duration of a price control period to assist charging stability. These parameters are reviewed, and any updated values published, prior to the start of the new price control period. These updated values will not take effect until the start of the second charging year within the new price control period. For example, for a price control period commencing on 1st April 2013, then charging parameter updates would be implemented in the methodology from 1st April 2014.

14.15.2~~1~~2 Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries, and will not take effect until the start of the second charging year after the review. The full criteria for determining generation zones are outlined in paragraph 14.15.2~~6~~7. The number of generation zones set for 2010/11 is 20.

14.15.2~~7~~8 The process behind the criteria in 14.15.2~~6~~7 is driven by initially applying the nodal marginal costs from the DCLF Transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1.00/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs for guidance.

14.15.3~~2~~3 In the methodology, the expansion constant is used to convert the marginal km figure derived from the transport model into a £/MW signal. The tariff model performs this calculation, in accordance with 14.15.6~~0~~1 – 14.15.6~~5~~6, and also then calculates the residual element of the overall tariff (to ensure correct revenue recovery in accordance with the price control), in accordance with 14.15.8~~1~~2.

14.15.3~~4~~5 For each circuit type and voltage used onshore, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure, these provide the basis of the onshore circuit expansion factors discussed in 14.15.4~~2~~3 – 14.15.4~~7~~8. In order to simplify the calculation a unity power factor is assumed, converting £/MVAkm to £/MWkm. This reflects that the fact tariffs and charges are based on real power.

14.15.3~~7~~8 The Weighted Average Cost of Capital (WACC) and asset life are ~~established~~ reviewed and updated in accordance with paragraph 14.15.4.~~at the start of a price control~~. Values then ~~and~~ remain constant throughout ~~a~~ the remainder of the price control period. The WACC used in the calculation of the annuity factor is the The Company regulated rate of return, this assumes that it will be reasonably representative of all licensees. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated ~~at the start of a price control period~~in accordance with paragraph 14.15.4. These assumptions provide a current annuity factor of 0.066.

14.15.38 The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by an ‘overhead factor’. The ‘overhead factor’ represents the total business overhead in any year divided by the total Gross Asset Value (GAV) of the transmission system. This is recalculated ~~at the start of each price control period~~in accordance with paragraph 14.15.4. The overhead factor used in the calculation of the expansion constant for 2009/10 is 1.8%. The overhead and annuitised costs are then added to give the expansion constant.

14.15.4~~0~~1 This process is carried out for each voltage onshore, along with other adjustments to take account of upgrade options, see 14.15.4~~5~~6, and normalised against the 400KV overhead line cost (the expansion constant) the resulting ratios provide the basis of the onshore expansion factors. The process used to derive circuit expansion factors for Offshore Transmission Owner networks is described in 14.15.5~~0~~1.

14.15.41 This process of calculating the incremental cost of capacity for a 400kV OHL, along with calculating the onshore expansion factors is carried out ~~for the first year of the price control~~ in accordance with paragraph 14.15.4 and is increased by inflation, RPI, (May–October average increase, as defined in The Company's Transmission Licence) each subsequent year of the price control period. The expansion constant for 2010/11 is 10.633.

14.15.5~~3~~4 Prevailing OFFSHORE TRANSMISSION OWNER specific expansion factors will be published in this statement. These shall be re-calculated ~~at the start of each price control~~in accordance with paragraph 14.15.4 when the onshore expansion constants are revisited.

14.15.5~~6~~7 The locational onshore security factor derived for 2010/11 is 1.8 and is based on an average from a number of studies conducted by The Company to account for future network developments. The security factor is reviewed ~~for each price control period~~in accordance with paragraph 14.15.4 and fixed for the ~~duration~~remainder of the price control period.

14.15.6~~8~~9 The process for calculating Local Substation Tariffs will be carried out ~~for the first year of the price control~~in accordance with paragraph 14.15.4 and will subsequently be indexed by RPI for each subsequent year of the price control period.

14.22 Example: Calculation of Zonal Generation Tariff

Let us consider all nodes in generation zone 4: Western Highland.

The table below shows a sample output of the transport model comprising the node, the wider nodal marginal km (observed on non-local assets) of an injection at the node with a consequent withdrawal at the reference node, the generation sited at the node, scaled to ensure total national generation equals total national demand.

Genzone	Node	Wider Nodal Marginal km	Scaled Generation
4	LAGG1Q	1113.41	0.00
4	CEAN1Q	1133.18	54.41
4	FASN10	1143.82	38.50
4	FAUG10	1100.10	0.00

4	FWIL1Q	1009.79	0.00
4	FWIL1R	1009.79	0.00
4	GLEN1Q	1123.82	43.52
4	INGA1Q	1087.40	16.74
4	MILL1Q	1101.55	0.00
4	MILL1S	1106.76	0.00
4	QUOI10	1123.82	15.07
4	QUOI1Q	(a) 120.49	0.00
4	LOCL1Q	(b) 082.41	0.00
4	LOCL1R	(c) 082.41	0.00
		(d) otals	168.24

In order to calculate the generation tariff we would carry out the following steps.

(i) calculate the generation weighted wider nodal shadow costs.

For zone 4 this would be as follows:

Genzone	Node	Wider Nodal Marginal km	Scaled Generation (MW)	Gen Weighted Wider Nodal Marginal km
4	CEAN1Q	1133.18	54.41	366.48
4	FASN10	1143.82	38.50	261.75
4	GLEN1Q	1123.82	43.52	290.71
4	INGA1Q	1087.40	16.74	108.20
4	QUOI10	1123.82	15.07	100.67
		Totals	168.24	

i.e. $\frac{1087.40 \times 16.74}{168.24}$

(ii) sum the generation weighted wider nodal shadow cost to give a zonal figure.
For zone 4 this would be:

(366.48+ 261.75 +290.71 + 108.20 + 100.67) km = **<u>1127.81km</u>**

(iii) modify the zonal figure in (ii) above by the generation/demand split correction factor. This ensures that the 27:73 (approx) split of revenue recovery between generation and demand is retained.

For zone 4 this would be say:

1127.81km + (-239.60 km) = **888.21 km**

This value is the generation/demand split correction factor. It is calculated by simultaneous equations to give the correct split of total revenue.

(iv) calculate the wider transport tariff by multiplying the figure in (iii) above by the expansion constant (& dividing by 1000 to put into units of £/kW).

For zone 4 and assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.8:

$$\frac{888.21\text{ km} * £10.07/\text{MWkm} * 1.8}{1000} = \underline{\mathbf{£16.10/kW}}$$

(v) If we assume (for the sake of this example) that the generation connecting at CEAN1Q connects via 10km of 132kV 100MVA rated single circuit overhead line from the nearest MITS node, with no redundancy, the substation is rated at less than 1320MW, and there is no other generation or demand connecting to this circuit, then:

a) referencing the table in paragraph 14.15.6~~7~~8, the local substation tariff will be £0.133/kW; and

b) running the transport model with a local circuit expansion factor of 10.0 applied to the 10km of overhead line connecting CEAN1Q to the nearest MITS node and the wider circuit expansion factors applied to all other circuits, gives a local nodal maginal cost of 100MWkm. This is the additional MWkm costs associated with the node's local assets. Applying the expansion constant of £10.07/MWkm and local security factor of 1.0 and dividing by 1000 gives a local circuit tariff of £1.007/kW.

(vi) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from generation (calculated as c.27% of total The Company TNUoS target revenue for the year) less the revenue which would be recovered through the generation transport tariffs divided by total expected generation.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from generation would be (27% x £1067m) = £288m. Assuming the total recovery from both wider generation transport and local generation tariffs is £70m and total forecast chargeable generation capacity is 67000MW, the Generation residual tariff would be as follows:

$$\frac{£288 - £70m}{65000MW} = \underline{£3.35/kW}$$

(vii) to get to the final tariff for a generator connecting at a particular node, we simply sum the generation residual tariff calculated in (vi), the wider zonal transport tariff calculated in (iv), the local substation tariff calculated in (v(a)) , and the local circuit tariff calculated in (v(b)). In this example:

For CEAN1Q : £16.10/kW + £3.35/kW + £0.135/kW + £1.007/kW = **£20.592 /kW**

To summarise, in order to calculate the generation tariffs, we evaluate a generation weighted zonal marginal km cost, modify by a re-referencing quantity to ensure that our revenue recovery split between generation and demand is correct, multiply by the security factor, then we add a constant (termed the residual cost) to give the overall tariff.

14.28 Stability & Predictability of TNUoS tariffs

Stability of tariffs

The Transmission Network Use of System Charging Methodology has a number of elements to enhance the stability of the tariffs, which is an important aspect of facilitating competition in the generation and supply of electricity. This appendix seeks to highlight those elements.

Each node of the transmission network is assigned to a zone. The result of this is to dampen fluctuations that would otherwise be observed at a given node caused by changes in generation, demand, and network parameters. The criteria used to establish generation zones are part of the methodology and are described in Paragraph 14.15.2~~6~~7.

These zones are themselves fixed for the duration of the price control period. The methodology does, however, allow these to be revisited in exceptional circumstances to ensure that the charges remain reasonably cost reflective or to accommodate changes to the network. In rare circumstances where such a re-zoning exercise is required, this will be undertaken in such a way that minimises the adverse impact on Users. This is described in Paragraph 14.15.~~29~~30.

In addition to fixing zones, other key parameters within the methodology are also fixed for the duration of the price control period or annual changes restricted in some way. Specifically:

- the expansion constant, which reflects the annuitised value of capital investment required to transport 1MW over 1km by a 400kV over-head line, changes annually according to RPI. The other elements used to derive the expansion constant are only reviewed at the beginning of a price control period to ensure that it remains cost-reflective. This review will consider those components outlined in Paragraph 14.15.3~~1~~2 to Paragraph 14.15.4~~1~~2.

- the expansion factors, which are set on the same basis of the expansion constant and used to reflect the relative investment costs in each TO region of circuits at different transmission voltages and types, are fixed for the duration price control. These factors are reviewed at the beginning of a price control period and will take account of the same factors considered in the review of the expansion constant.

- the locational security factor, which reflects the transmission security provided under the NETS Security and Quality of Supply Standard, is fixed for the duration of the price control period and reviewed at the beginning of a price control period.

Predictability of tariffs

The Company revises TNUoS tariffs each year to ensure that these remain cost-reflective and take into account changes to allowable income under the price control and RPI. There are a number of provisions within The Company's Transmission Licence and the CUSC designed to promote the predictability of annually varying charges. Specifically, The Company is required to give the Authority 150 days notice of its intention to change use of system charges together with a reasonable assessment of the proposals on those charges; and to give Users 2 months written notice of any revised charges. The Company typically provides an additional months notice of revised charges through the publication of "indicative" tariffs. Shorter notice periods are permitted by the framework but only following consent from the Authority.

These features require formal proposals to change the Transmission Use of System Charging Methodology to be initiated in October to provide sufficient time for a formal consultation and the Authority's veto period before charges are indicated to Users.

More fundamentally, The Company also provides Users with the tool used by The Company to calculate tariffs. This allows Users to make their own predictions on how future changes in the generation and supply sectors will influence tariffs. Along with the price control information, the data from the Seven Year Statement, and Users own prediction of market activity, Users are able to make a reasonable estimate of future tariffs and perform sensitivity analysis.

To supplement this, The Company also prepares an annual information paper that provides an indication of the future path of the locational element of tariffs over the next five years.[6] This analysis is based on data included within the Seven Year Statement. This report typically includes:

- an explanation of the events that have caused tariffs to change;
- sensitivity analysis to indicate how generation and demand tariffs would change as a result of changes in generation and demand at certain points on the network that are not included within the SYS;
- an assessment of the compliance with the zoning criteria throughout the five year period to indicate how generation zones might need to change in the future, with a view to minimising such changes and giving as much notice of the need, or potential need, to change generation zones; and
- a complete dataset for the DCLF Transport Model developed for each future year, to allow Users to undertake their own sensitivity analysis for specific scenarios that they may wish to model.

There are a number of charging parameters that, for charging stability purposes, are reviewed normally only once prior to the start of a new price control period. Any required changes to these parameters are published before the start of the new price control period, but will not take effect until the start of the second charging year within the new price control period. This allows customers to

[6] http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

understand the impact of these changes on tariffs and ensure the predictability of TNUoS charges is maintained.

In addition, The Company will, when revising generation charging zones ~~prior to~~at the start of a new price control period, undertake a zoning consultation that uses data from the latest information paper. The purpose of this consultation will be to ensure tariff zones are robust to contracted changes in generation and supply, which could be expected to reduce the need for re-zoning exercises within a price control period. To ensure predictability of TNUoS charges is maintained, implementation of such generation re-zoning will take place at the start of the second charging year within the new price control period.

Annex 3 – Timeline

25 Oct 2012	CUSC Modification Proposal and request for Urgency submitted
26 Oct 2012	Proposal and request for Urgency considered by CUSC Panel Panel's view submitted to Ofgem for consultation
31 Oct 2012	Ofgem view on urgency provided
5 Nov 2012	Code Administrator Consultation issued for 10 working days
19 Nov 2012	Consultation closes
20 Nov 2012	Draft FMR published for industry comment (1 working day)
21 Nov 2012	Deadline for comments
22 Nov 2012	Draft FMR circulated to Panel (2 working days' review)
27 Nov 2012	Special Panel meeting for Panel Recommendation Vote
27 Nov 2012	Final FMR circulated for Panel comment
29 Nov 2012	Deadline for Panel comment (2 working days' review)
30 Nov 2012	Final report sent to Authority for decision
18 Dec 2012	Indicative Authority Decision due (12 working days)
19 Dec 2012	Implementation Date
21 Dec 2012	NGET publishes Indicative TNUoS tariffs

Annex 4 – Panel Urgency Request to Authority

Mobile Telephone Number: 07770 341581
e-mail: miketoms53@btinternet.com

Abid Sheikh
Industry Codes Manager
Ofgem
By email

29 October 2012

Dear Abid

CUSC Modifications Panel Views on request for Urgency for CMP214: Implementation of TNUoS charging parameter updates

On 25th October 2012, National Grid Electricity Transmission plc raised CMP214, with a request for the proposal to be treated as an Urgent CUSC Modification Proposal. The CUSC Modifications Panel ("the Panel") considered CMP214 and the associated request for urgency at its meeting on 26th October. This letter sets out the views of the Panel on the request for urgent treatment and the procedure and timetable that the Panel recommends, should the Authority grant urgency.

Request for Urgency

The Panel considered the request for urgency with reference to Ofgem's Guidance on Code Modification Urgency Criteria. The majority view of the Panel is that CMP214 should be treated as an Urgent CUSC Modification Proposal, for the reasons set out below:

- CMP214 refers to an imminent issue;
- The issues addressed by CMP214 may cause a significant commercial impact on parties, consumers or other stakeholders;

In the discussion members of the Panel also noted a number of concerns over granting urgency, set out below:

- Using an urgent process holds an inherent risk of unintended consequences, which may arise due to there being insufficient time for all aspects of a Modification Proposal to be considered;
- One Panel Member questioned whether CMP214 could have been raised earlier;
- A Panel Member felt that it was not clear from the information within the Modification Proposal form whether Suppliers' views support the need for urgency;
- With regard to the materiality of the proposal, if the issues are not material, then the proposal should not be treated as urgent; however if the issues are material, then the urgent process will not allow sufficient industry engagement;
- Allowing CMP214 to progress in urgent timescales will create more unpredictability for customers.

Procedure and Timetable

The Proposer included a proposed timeline with the Modification Proposal, which set out recommended process steps and dates (appended to this letter). Having agreed to the principle of urgency, the Panel discussed an appropriate process. One Panel Member felt that a Workgroup should be convened to consider CMP214, but recognised that there was not sufficient time for a full process to be run.

The Panel Members agreed that, if the Authority were to grant Urgency, the timetable attached should be used. Panel Members noted that the timetable assumes two decisions to be provided by the Authority by certain dates, including a decision on this Urgency request by the end of October. We appreciate that it is not within the gift of the Panel to require this to happen.

Please do not hesitate to contact me if you have any questions on this letter or the proposed process and timetable. I look forward to receiving your response.

Yours sincerely

Michael Toms
CUSC Panel Chair

Appendix: Proposed Process and Timetable for Urgency

25 Oct 2012	CUSC Modification Proposal and request for Urgency submitted
26 Oct 2012	CUSC Panel considers Proposal and request for Urgency
29 Oct 2012	Panel's view on urgency submitted to Ofgem for consultation
31 Oct 2012	Ofgem view on urgency provided
1 Nov 2012	Code Administrator Consultation issued for 10 working days
15 Nov 2012	Consultation closes
16 Nov 2012	Draft FMR published for industry comment (1 working day)
19 Nov 2012	Deadline for comments
20 Nov 2012	Draft FMR circulated to Panel (2 working days' review)
23 Nov 2012	Special Panel meeting for Panel Recommendation Vote
23 Nov 2012	Final FMR circulated for Panel comment
27 Nov 2012	Deadline for Panel comment (2 working days' review)
28 Nov 2012	Final report sent to Authority for decision
14 Dec 2012	Indicative Authority Decision due (12 working days)
17 Dec 2012	Implementation Date
21 Dec 2012	NGET publishes Indicative TNUoS tariffs

Annex 5 – Authority Response to Panel Urgency Request

Michael Toms
CUSC Panel Chair
c/o National Grid Electricity
Transmission plc
National Grid House
Warwick Technology Park
Gallows Hill
Warwick CV34 6DA

Our Ref: CUSC/Mod/CMP214
Email: industrycodes@ofgem.gov.uk

Date: 2 November 2012

Dear Mr. Toms,

CUSC Modifications Panel request for urgency for CMP214: Implementation of TNUoS charging parameter updates

On 29 October 2012 the Connection and Use of System Code (CUSC) Modifications Panel requested that modification proposal CMP214: '*Implementation of TNUoS charging parameter updates*'[1] should be treated as an urgent modification proposal.

This letter sets out our decision to ***grant*** the request. However, we are disappointed with the process that National Grid Electricity Transmission (NGET) has followed in this matter which has resulted in the need to consider these issues in an urgent manner.

This letter also highlights a number of areas that we expect to be addressed in the development of the proposal before it comes to us for a decision.

The Proposal

There are a number of provisions within the current regulatory framework that are designed to enhance the stability, and promote the predictability, of Transmission Network Use of System (TNUoS) tariff levels. These include a requirement for NGET to publish final tariff levels in January ahead of the start of a new charging year[2]. Historically, NGET have also published forecast TNUoS tariff levels in mid-December, although this is not a requirement of the licence or code framework.

In accordance with the default notification timescales, NGET has developed supporting charge setting processes to guide the relevant licensees towards providing forecast revenue information to NGET in a manner designed to improve accuracy and give customers additional information on the predicted tariff movements[3].

Implicit within the charge setting process is the need to make forecasts when calculating the annual total allowed revenue to be recovered through tariffs levied by NGET. During a price control period the total allowed revenue comprises relatively stable forecast cost submissions by the existing transmission owners. The difference between the published forecast of tariffs in December and the final tariffs levels have therefore been minimal.

NGET does not believe that the default charge setting process provides an appropriate level of accuracy and predictability of tariff levels to customers for the upcoming charging year,

[1] The CUSC Panel's letter requesting urgent treatment for CMP214 is on National Grid's website: http://www.nationalgrid.com
[2] CUSC section 3.14.3 requires NGET to provide at least 2 month advance written notice of any revised charges.
[3] For example, the SO-TO Code Processes (STCPs) 13-1 and 14-1 requires each transmission licensee to send NGET their best forecast of its revenue requirement for the next financial year by 1 November and licensees' final forecast revenue by 25 January to allow NGET to publish tariffs for the next financial year by 31 January.

the first year of the new price control period. NGET contends that the full impact on TNUoS tariff levels cannot be accurately analysed and communicated in draft form to customers until certain financial information, used in the derivation of the locational element of TNUoS tariffs, can be confirmed. During a price control period, such information is relatively stable and is available for validation and use in NGET's charging model from November of each charging year. In this charging year, the year prior to the commencement of a new price control period, NGET notes that such information will only be confirmed once the final proposals of the RIIO-T1 price controls are announced. This information is estimated to be available in mid-December 2012 based on current RIIO publication forecasts.

We understand from the modification proposal that NGET believes that there are deficiencies in applying the current charge setting process. In particular -

- The magnitude of change envisaged to the financial information will produce significant movements in tariff levels in some areas relative to the existing tariff levels (2011/12), creating an unacceptable degree of tariff volatility in some areas.
- Movements in these charging input parameters will drive changes in the composition of the applicable generation charging zones boundaries determined in accordance with the zoning criteria in the TNUoS charging methodology[4], exacerbating the potential increase in tariff volatility.
- The updated parameters would be applied with limited notice to customers for them to efficiently incorporate the changes into their pricing structures.

In light of the above concerns, NGET proposes to delay the implementation of the update of the revised charging parameters and the impact on generation zoning boundaries to 1 April 2014, so that customers can have greater notice of these changes.

Panel Discussion

The CUSC Modifications Panel discussed CMP214 at its meeting on 26 October 2012 when a number of concerns were raised about whether urgent treatment is appropriate. The Panel agreed by majority that the proposal was linked to an imminent 'date' issue, namely, publication of draft TNUoS tariff levels before Christmas 2012 and final tariff publication by 31 January 2013. The Panel also agreed that changes to charges <u>might</u> have a significant commercial impact on CUSC parties, consumers and other stakeholders. However, the Panel also questioned whether the circumstances in which NGET raised CMP214 merits urgent treatment, e.g. whether NGET could have raised the proposal earlier and whether there would be sufficient stakeholder engagement through an urgent process.[5]

Our Views

Taking into account the Panel's majority view, the reservations expressed by Panel members and our consideration of the criteria for granting urgent status to a modification proposal set out in our published guidelines[6], we are satisfied, on balance, that the proposal meets the criteria. In particular, we consider that the proposal is:

Linked to an imminent issue or a current issue that if not urgently addressed may cause:

a) *a significant commercial impact on parties, consumers or other stakeholder(s);*

We accept that there is an imminent 'date' issue that means that the modification should be addressed through an urgent timetable. Whether NGET should review and update the relevant charging parameters for implementation on 1 April 2013 or a year later as

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[4] See CUSC section 14.15.26. We also note that section 14.28 requires NGET to undertake a zoning consultation "*when revising generation charging zones prior to a new price control period*".
[5] The CUSC Panel's views are set out in the letter – see footnote 1.
[6] www.ofgem.gov.uk/Licensing/IndCodes/Governance/Documents1/Ofgem%20Guidance%20on%20Code%20Modification%20Urgency%20Criteria.pdf

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proposed should be considered through an urgent assessment timetable. However, in accepting that this 'date' issue exists, we are also mindful of the Panel's concerns about the aim of the proposal. We consider that this modification could have been raised earlier as the RIIO-T1 timetable has been known for some time, and that earlier and more thorough consideration of alternative options to raising a CUSC modification could have been explored.

We have specific concerns that must be addressed by the urgent assessment of CMP214 and which may affect our ability to form an opinion on it once a final report is presented for decision. These concerns are directly affected by the urgency with which CMP214 is being assessed, and so must be addressed fully through the urgent process, namely -

- NGET must use its best endeavours to ensure that stakeholders can understand the core intent of the proposal and its implications to allow sufficient industry engagement. NGET must therefore demonstrate with sufficient clarity the current charge setting process and its reasons why and how the proposed change will have a significant impact on parties. The proposal currently fails to specify how this impact will arise, how volatility will be reduced and the implied beneficial trade off between greater predictability and a reduction in cost reflectivity as a result of this proposal will be achieved. The Final Modification Report (FMR) should further elaborate on the evidence presented through the consultation to address these concerns.

- As part of the assessment, we would expect NGET to provide clarity and detail regarding the work they intend to do in reviewing and updating the charging parameters including any revisions arising from network data, the consequences of RIIO-T1 proposals and possible revisions to generation zones. In each case, NGET should present the likely impact on tariff volatility.

- As part of the assessment, NGET should also clarify and quantify the impact on cost recovery of a one-year delay to the implementation of the revised and updated charging parameters should the proposal be approved.

In agreeing to the urgent assessment of the proposal, we are mindful of concerns that the assessment will not engage industry as effectively as through a standard modification timetable. In addressing our concerns above, NGET must seek as far as possible to engage with those parties most likely to be affected by the proposal to establish a robust evidence base of stakeholder views.

Urgency Timetable

The Authority consents to urgency on the grounds that this proposal meets the urgency criteria. We note the urgent timetable presented by the Panel. In our view, the timetable should allow for industry consultation of a minimum of 10 Working Days and for the FMR to be presented to us by 30 November 2012 in order that we can consider our decision.

For the avoidance of doubt, in accepting this request for urgency, we have made no assessment of the merits of the modification proposal and nothing in this letter in any way fetters the discretion of the Authority in respect of this modification proposal.

If you have any queries in relation to the issues raised in this letter, please email: industrycodes@ofgem.gov.uk.

Yours sincerely

Andrew Burgess
Associate Partner – Transmission and Distribution policy

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

Annex 6 – Latest National Grid view on potential changes to the TNUoS charging parameters and their potential impact

The following is the latest National Grid view on potential changes to the TNUoS charging parameters and generation charging zones, and their potential impact on tariffs from the start of the RIIO-T1 price control period in April 2013. Whilst it provides an indication of what these parameters could be following the introduction of the new price control, figures presented are subject to further change and should be not taken as final values.

Indicative charging parameter changes

The table below lists all of the charging parameters that are required under the TNUoS charging methodology to be reviewed by the start of the new price control period. Their full description including their role in the derivation of TNUoS tariffs is provided in Annex 7.

Parameter	**Likely change**	**Justification**
Expansion Constant	Increase[7]	Underlying efficient capital costs
Annuity Factor	Decrease	Finance package and opex allowance included in NGET's Initial Proposals
Overhead Factor	Neutral	Finance package and opex allowance included in NGET's Initial Proposals
Capital Costs	Increase	Underlying efficient capital costs
Cable Expansion Factors	Decrease	Underlying capital costs
OHL Expansion Factors	Increase	Reduced uprating of transmission circuits
Security Factor	Neutral	Consistent level of redundancy required

Table A1 – Indicative charging parameter changes

Potential impact on wider tariffs

The charts below shows an initial view of the potential changes to wider generation and demand TNUoS tariffs following changes to the above parameters, along with the likely allowed revenue requirements in 2013/14. They are based on the initial demand and generation backgrounds for 2013/14 as of April 2012 and an initial view of the updated expansion constant and expansion factors. Annex 8 provides the tariff information in tabular form.

[7] likely increase from £11.7/MWkm to around £13/MWkm

Generation tariff

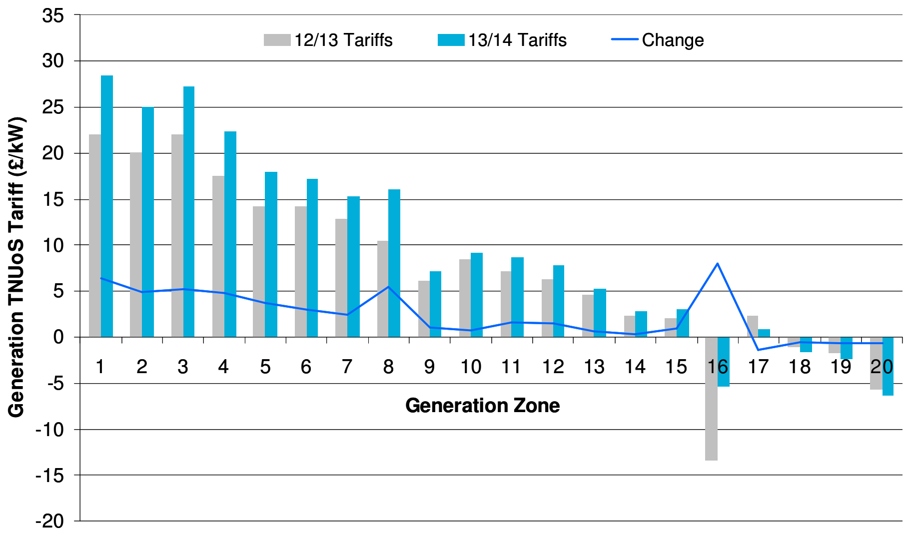

Chart A1 – Initial view of potential 2013/14 wider generation tariffs with charging parameter changes

It should be noted that this chart does not account for any re-zoning of generation. The general pattern of the charts shows an increase in zonal tariffs for generators located in the north (zones 1-15) and a slight reduction for those located in the south (zones 17-20). This is consistent with a general uplift in revenues to be recovered, which is applied equally across all zones, coupled with a stretch in the locational elements from north to south of Great Britain due to:

a. changes in the generation and demand background;

b. a potential increase in the expansion constant and expansion factors.

Zone 16 does not follow this trend due to a significant change in the local generation background affecting the locational signal.

Demand tariffs

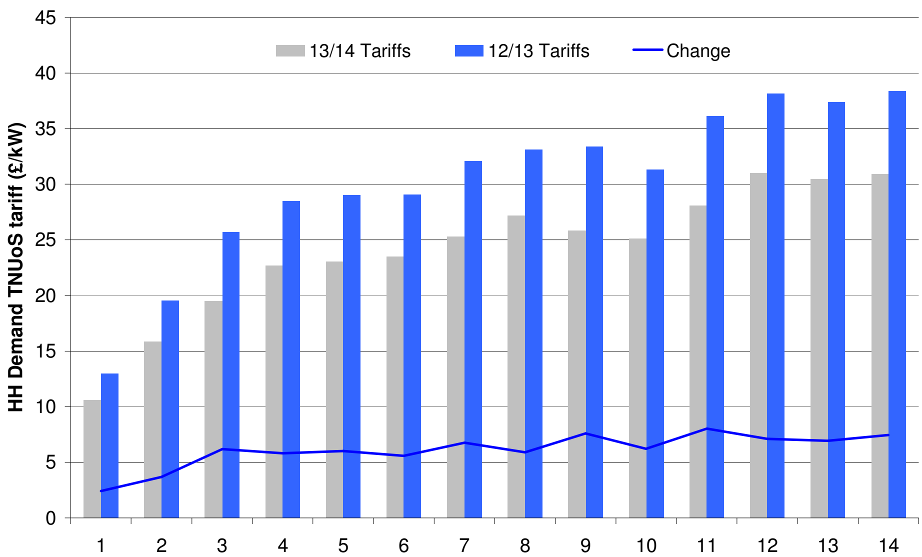

Chart A2 – Initial view of potential 2013/14 HH demand tariffs with charging parameter changes

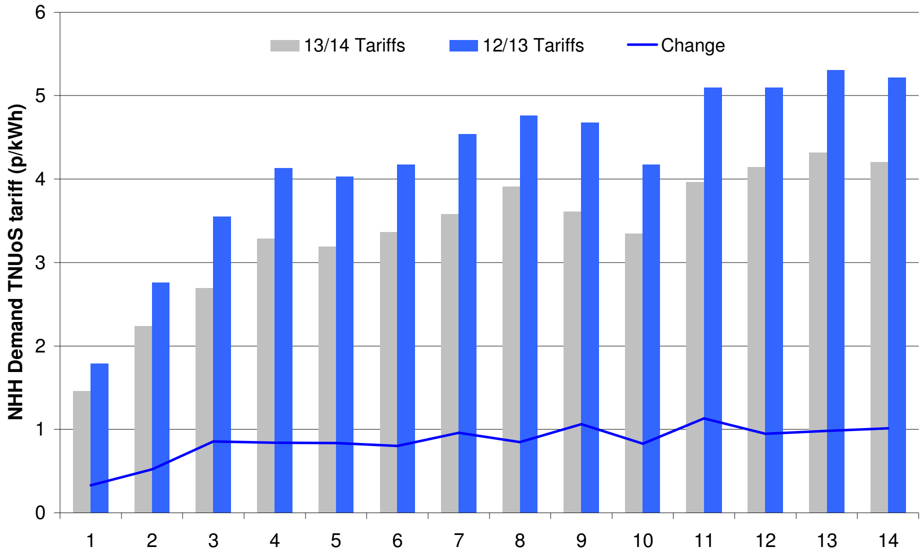

Chart A3 – Initial view of potential 2013/14 wider generation NHH demand tariffs with charging parameter changes

The demand tariffs tend to show the reverse trend to the generation tariffs with the increases smallest in Scotland (Zones 1 and 2) and increasing towards southern England. The locational changes are due to the same drivers i.e. expected changes in the generation and demand background and the potential increases in the expansion constant and expansion factors.

Charts A4 and A5 show the direct potential impact of the input parameter changes by comparing changes in indicative 2013/14 tariffs. The tariff changes shown in magenta have been estimated with the existing charging parameters, whilst those in blue have been produced with updated estimated charging parameter values. In both cases, the generation and demand backgrounds have been based on data for 2013/14 as of April 2012. This means the difference between the magenta and blue lines represents the change due to updates to the charging parameters. The shaded area represents the potential uncertainty around charging parameter changes.

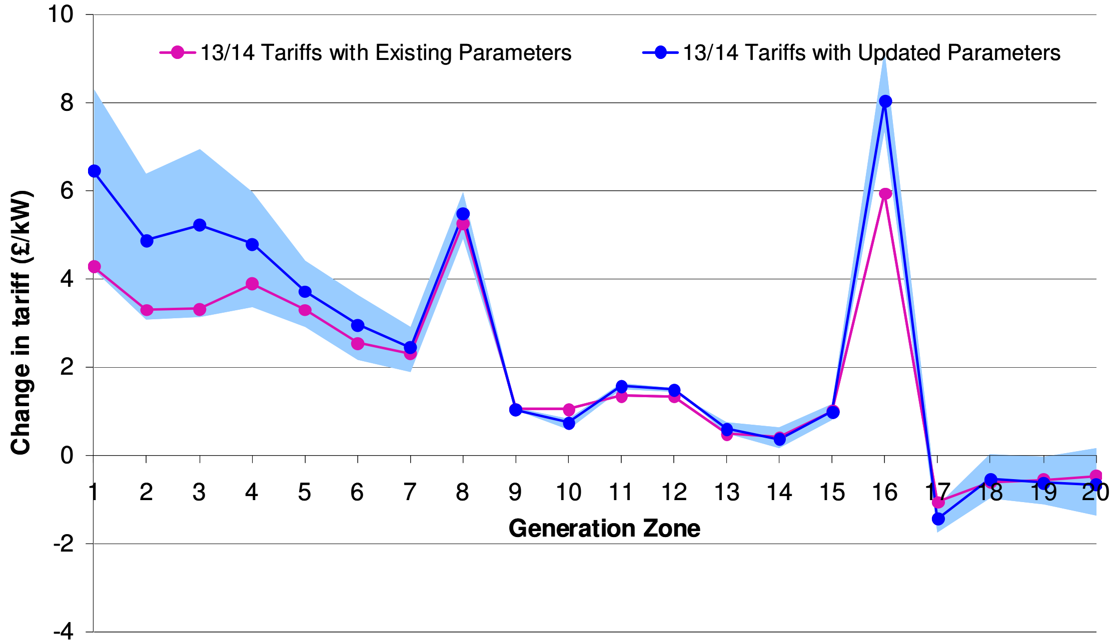

Chart A4 – Potential impact of charging parameter changes on indicative 2013/14 wider generation tariffs

Chart A4 shows the potential impact on generation zonal tariffs. It can be seen from the chart that there the greatest potential for both change and uncertainty at the peripheries of the transmission system. For example, initial analysis suggests a potential increase of over £2/kW in Zone 1 due to changes to charging parameters alone, but that this change could be between £0/kW to £4/kW. This range is due the current uncertainty regarding the data required to re-assess the charging parameters.

When comparing with the tariffs presented in chart A1 it can be estimated that around a third of the annual change to Zone 1 tariffs would be due to charging parameter changes, although the figure could be as high as 50%. This is due to the potential changes to the expansion constant and expansion factors.

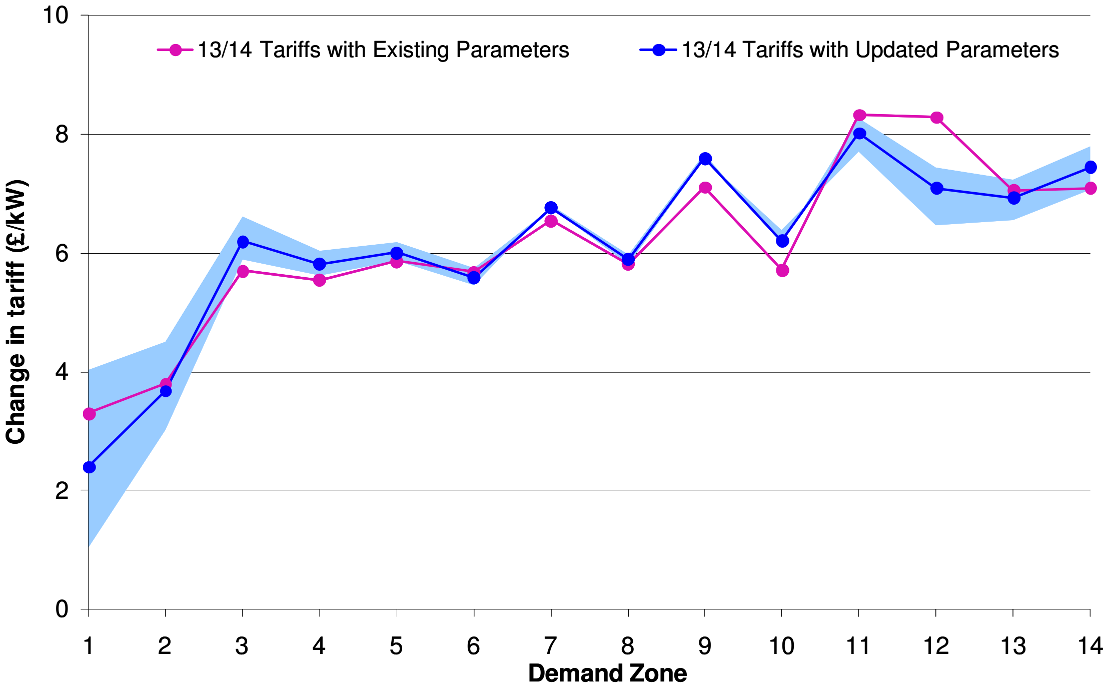

Chart A5 – Potential impact of charging parameter changes on indicative 2013/14 wider HH demand tariffs

Chart A5 provides a similar view for zonal HH demand tariffs. Again, the greatest changes are in the areas most greatly affected by changes to the expansion constant and expansion factors; zone 1 (northern Scotland) and zone 12 (London). As a result, these zonal tariffs are also exposed to the highest level of uncertainty. For zone the potential tariff changes range from an increase of over £0.5/kW to a reduction of over £1/kW.

Potential Impact on Generation Charging Zones

Generation charging zones were last updated in 2006. The following view is presented based on the draft 2013/14 transport model updated with likely values of the expansion constant and expansion factors.

An initial re-zoning view was taken to minimise both the number of zones and also the number of changes from the current position. The results of this consideration are presented in the table below as a view of the likely areas where zone changes may be required. The current zoning criterion remains ± £1/kW. Zones shown in red (a total of 9) breach this limit with two further zones (zones 8 and 19) being close to this limit.

Zone	Zone Name	Zonal Spread (£/kW)
1	North Scotland	2.1
2	Peterhead	0.0
3	Western Highland & Skye	4.4
4	Central Highlands	0.8
5	Argyll	3.4
6	Stirlingshire	2.4
7	South Scotland	7.1
8	Auchencrosh	1.9
9	Humber & Lancashire	5.3
10	North East England	0.0
11	Anglesey	0.0
12	Dinorwig	0.0
13	South Yorks & North Wales	2.4
14	Midlands	1.4
15	South Wales & Gloucester	6.0
16	Central London	0.0
17	South East	2.8
18	Oxon & South Coast	0.4
19	Wessex	1.8
20	Peninsula	1.3

Table A2 – Potential breeches of TNUoS Generation Zonal ± £1/kW Criteria

On this basis it is estimated that there will be a requirement for an additional 6-10 generation zones, with some further indicative detail being;

- An additional 1-2 zones in northern Scotland.
- The splitting of southern Scotland into east and west. This may require an additional 2-3 zones.
- An additional 1-2 l zones in the north midlands.
- The potential for a reduced number of zones in north west Wales.
- 2 additional zones in south Wales.
- An additional zone required for the Thames Estuary / south east coast area.

Whilst National Grid will attempt to minimise the impact of zonal changes in accordance with paragraph 14.15.27 of Section 14 of the CUSC, the impact of each zonal change will be unique, and could result significant step changes for generators in affected zones. Whilst this impact cannot be accurately quantified at this stage, an illustrative example is provided in Annex 7.

Comparison with changes made at the start of the last price control period

These charging parameters and generation charging zones were last reviewed and updated in 2006 prior to the start of the last price control period, TPCR4, in April 2007. Table A3 below shows the potential impact of the current charging parameter review against the previous review at the start of TPCR4. Expansion constant values are quoted in 2012/13 prices. RIIO-T1 figures are indicative only at this stage.

Parameter	BETTA (April 05)	TPCR 4 (April 07)	RIIO-T1 (April 13)
Expansion Constant (£/MWkm)	12.35	11.72	Approx.13
OHL Expansion Factors	1.0 – 2.6	1.0 – 2.7	1 – 3
Cable Expansion Factors	22.4 – 30.2	20.7 – 27.9	12 – 15
Locational Security Factor	1.8	1.8	1.8
No. of generation zones	21	20	26-30

Table A3 – Comparison of Charging Parameter Updates at the start of price control periods

Generally, the changes currently forecast for the review of charging parameters and generation charging zones at the start of RIIO-T1 are expected to be greater than those experienced at TPCR-4. This is in part because TPCR4 reviewed these values only two years after their review at part of the establishment of the British Electricity Trading Arrangements (BETTA) in April 2005.

The review implemented in April 2007 saw a reduction in the expansion constant of £0.63/MWkm. The change at the RIIO-T1 view is currently considered to be an increase of around £1.2/MWkm. As this change is an increase, this will see a stretching of the locational signals within TNUoS charges (i.e. the range between the highest and lowest tariff increases), whilst the 2007 change saw a contraction. There are also changes to the expansion factors, with some more noticeable reductions to relative cable costs and some increases to some OHL costs. The impact of these is again to stretch the locational signals.

The TPCR-4 review of generation charging zones saw a reduction of one generation charging zone, i.e. minimal change. The current forecast for the generation charging zone review at the start of RIIO-T1 will see an additional 6-10 zones being created. This will likely have a much greater impact with some generators seeing significant increases and others significant decreases in their zonal charges. The reasons for this are explained further in Annex 7.

Next Steps for Review of Charging Parameters and Generation Charging Zones

The review of charging parameters and generation charging zones is dependent on information from two main sources; network data and financial data. Whilst the majority of this information has now been received by National Grid, some data will not be available until later this year. Additionally, there are some areas where National Grid are still reviewing data presented.

Table A4 below indicates the dependencies of the charging parameters on these two data sources.

	Network Data Dependent	Financial Data Dependent
Expansion Constant	No	Yes
Expansion Factors	No	Yes
Security Factor	Yes	No
Generator Zones	Yes	Yes

Table A4 – Data dependencies of charging parameters

The purpose of this section is to inform the progress of National Grid in capturing and reviewing this information to date, and provide an intended timeline for the completion of the review. National Grid will provide a further update to industry at the TCMF on 28th November.

Network Data

Network data includes information relating to the National Electricity Transmission System as well as generation and demand backgrounds. This data is required to be annually updated, with the updated information populating the Transport and Tariff model. Data is provided to National Grid from generators, DNOs, Directly-Connected Customers and onshore TOs by the end of October, which allows National Grid to publish draft TNUoS tariffs before Christmas. Prior to being used in the models, National Grid reviews and makes independent checks this data, to best ensure the data is free from error and all changes are understood.

As such, this data can significantly alter the transport model marginal MWkm flows. National Grid therefore requires this information be updated prior to finalising the locational security factor and reviewing generation charging zones.

On this basis, it is currently anticipated that the locational security factor will be finalised before the end of November. The review of generation charging zones is also dependent on the confirmation of financial information and so cannot be completed in this timescale.

Financial Data

Financial data relates to the following elements. These are described in further detail in Annex 7.

1. *Capital (Investment) Costs.* This information is required to enable National Grid to set the expansion constant and expansion factors. Information is provided from the onshore TOs. Whilst this data has been supplied to allow review ahead of implementation of RIIO-T1, there is still ongoing dialogue between National Grid and other onshore TOs to understand the changes to the data from that provided for the TPCR-4 review. This is because there are certain areas which suggest a significant change to capital costs and plans, which would likely impact on locational elements of certain user's

charges, National Grid therefore need to ensure that it is correct that these changes are reflected in the TNUoS methodology. This work is ongoing but National Grid hopes it will be completed by early December.

2. *The Overhead Factor.* The overhead factor is required to ensure that the expansion constant and expansion factors share the business costs, which include maintenance and business rates. Against this background, the overhead factor represents an allocation of operating costs to the assets. The calculation of the overhead factor requires data provided by the onshore TOs and operating cost information from the price control. On the basis that final proposals for the RIIO-T1 price controls will be published in mid-December, National Grid will endeavour to update the overhead factor for inclusion in draft tariffs. Any changes to the timeline for publishing RIIO-T1 final proposals will impact on the timescales for updating the overhead factor.

3. *Weighted Average Cost of Capital (WACC) / Annuity Factor.* This financial metric relates to the cost of capital for a transmission company and is used in the calculation of the annuity factor, which in turn is used in the calculation of the expansion constant and expansion factors. The TNUoS charging methodology requires that the WACC used in the calculation of the annuity factor is the National Grid regulated rate of return, as this assumes that it will be reasonably representative of all licensees. This rate of return will not be agreed until at least mid-December, when final RIIO-T1 proposals for NGET are published. On the basis that this is finalised in mid-December, National Grid believe that the review can be completed to allow publishing of draft TNUoS tariffs by Christmas.

Providing an agreement is reached on the RIIO-T1 proposals for National Grid in mid-December, then the WACC and overhead factor can be established, and hence the annuity factor, expansion constant and expansion factors can be finalised. This will then allow the generation charging zones to be reviewed. National Grid will seek to provide more information on re-zoning in draft tariffs; however, given the resource requirements to undertake a full rezoning exercise this may not be completed until the end of January in time for publication of final tariffs.

It should be noted that the review of the charging parameters and generation charging zones associated with the RIIO-T1 price control, is intended to be completed to the above timeline whatever the outcome of CMP214. CMP214 seeks to review the implementation date for these changes only.

In the event that CMP214 is approved by the Authority in line with the timeline published in Annex 3, draft tariffs will be published in December 2012 derived from a 2013/14 Transport and Tariff model with updated network data, but with no updates to charging parameters and generation charging zones that are reviewed at the start of a price control period. In this case, National Grid will publish alongside the draft tariffs, the updated values to charging parameters and generation charging zones.

In the event that CMP214 is rejected by the Authority in line with the timeline published in Annex 3, draft tariffs will be published in December 2012 derived from a 2013/14 Transport and Tariff model with both updated network data, and also updates to charging parameters and generation charging zones that are reviewed at the start of a price control period. These updated values with be published, for clarity, alongside the draft tariffs.

In the event the Authority has not made a decision on CMP214 in line with the timeline published in Annex 3, two sets of draft tariffs will be published in December 2012 based on whether this modification proposal is approved or rejected.

Annex 7 – The key elements of the TNUoS charging methodology affected by this proposal and their role in the setting of TNUoS tariffs

The purpose of this annex is to provide further explanation of the TNUoS charging parameters affected by this proposal and the generation charging zones. It includes an explanation of their role in the setting of TNUoS tariffs and their impact on tariff volatility.

Overview of TNUoS Charging Methodology

The TNUoS Charging Methodology is laid out in the Statement of the Transmission Use of System Charging Methodology in Section 1 of Part 2 of Section 14 of the CUSC[8].

TNUoS charges are set to recover the Maximum Allowed Revenue (MAR), as set by the Authority at the time of the Transmission Owner (TO) 's price control review to recover the costs of the TO activity function of the transmission businesses of each transmission licensee for the succeeding price control period.

TNUoS charges are collected through a number of tariffs. TNUoS tariffs are comprised of two separate elements. Firstly, a locational element which reflects the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations (i.e. provides a cost reflective signal). Secondly, a non-locationally varying element relating to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

CMP214 seeks to alter the timing of changes to certain parameters (including generation charging zones) which affect the locational element. This means changes to these parameters do not affect the overall collection of MAR.

The TNUoS methodology refers to two models which are used to derive TNUoS tariffs;

- *The Transport Model.* This calculates the marginal cost of investment (expressed in MWkm) in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system.

- *The Tariff Model.* The tariff model converts the marginal MWkm figure derived from the transport model into a £/MW signal, and also then calculates the residual element of the overall tariff .

[8] The CUSC - Section 14

Charging Parameters that are required to be reviewed at a price control review and their role in the setting of TNUoS tariffs

Six charging parameters are affected by CMP214. These are;

- The Expansion Constant
- The Expansion Factors
- The Locational Security Factor
- The Annuity Factor
- Capital Costs
- The Overhead Factor

The annuity factor, capital costs and the overhead factor are all used to calculate the expansion constant and expansion factors.

The expansion factors are used in the transport model to reflect the difference in cost between cabled routes and overhead line routes, routes of different voltage. As the transport model expresses cost as marginal km (irrespective of cables or overhead lines), some account needs to be made of the fact that investment in these other types of circuit is more expensive than for 400kV overhead line. This is done by effectively 'expanding' these more expensive circuits by the relevant circuit expansion factor, thereby producing a larger marginal kilometre to reflect the additional cost of investing in these circuits compared to 400kV overhead line.

The expansion constant and locational security factor are used in the calculation of the initial transport tariffs. Both these charging parameters are simple multipliers to the generation and demand zonal marginal km outputs from the transport model.

Each of the parameters is described in more detail below, as is their impact on TNUoS tariffs.

<u>1. Capital Costs</u>

These are the base capital costs used to estimate the cost of transmission infrastructure investment. They are used to provide average unit cost of investment for inclusion in tariffs via the expansion constant and expansion factors.

Capital cost data includes information provided from all onshore Transmission Owners (TOs). They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, etc.). The objective of these adjustments is to make the costs reflect current prices. This cost data represents National Grid’s best view; however it is considered as commercially sensitive and is therefore treated as confidential.

2. The Annuity Factor

The annuity factor converts the average capital cost of transmission investment into an annuitised figure for use in the expansion constant and expansion factors. The formula used to calculate of the annuity factor is shown below.

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

The Weighted Average Cost of Capital (WACC) and asset life are currently reviewed and updated at the start of a price control period. Values then remain constant throughout a price control period. The WACC used in the calculation of the annuity factor is the National Grid regulated rate of return, this assumes that it will be reasonably representative of all licensees. It is not confirmed until the outcome of the price control review is known and agreed. The asset life used in the calculation is 50 years; the appropriateness of this is reviewed when the annuity factor is recalculated. The current annuity factor is 0.066. Based on the capital cost of 400kV overhead line used in the TPCR4 review, a change of 0.1% change on WACC can be roughly estimated as having a £0.1/MWkm impact on the expansion constant. Based on the initial view of 2013/14 tariffs published in April 2012, this would increase the range of:

- generation tariffs by 28 p/kW
- HH demand tariffs by 21 p/kW
- NHH demand tariffs by 0.03 p/kWh

However, the higher the capital cost, the greater the impact of a change of WACC on the final expansion constant.

3. The Overhead Factor

The overhead factor is required to ensure that the expansion constant and expansion factors share the business costs, such as maintenance and business rates in addition to consideration of annuitized capital costs. The overhead factor represents the total business operating costs in any year divided by the total Gross Asset Value (GAV) of the transmission system. It is currently recalculated at the start of each price control period.

4. The Expansion Constant

The expansion constant, expressed in £/MWkm, represents the average annuitised £/MW cost of building 1km of 400kV overhead line and is derived from the actual costs of 400kV overhead line construction, including an estimate of the cost of capital, to provide for future system expansion. It is used to convert the marginal km figure derived from the transport model into a £/MW signal. The expansion constant is reviewed and updated at the start of a price control period, with annual RPI updates during the price control period. In 2012/13 the expansion constant is £ 11.723618 /MWkm.

Calculating the Expansion Constant
The table below, taken from paragraph 14.15.35 of Section 24 of the CUSC, shows the first stage in calculating the onshore expansion constant, where capital costs of investment are averaged to determine an average unit cost. A range of overhead line types is used and the types are weighted by recent usage on the transmission system. This is a simplified calculation for 400kV overhead line using example data:

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

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

Table A5 - 400kV OHL average capital cost calculation

The weighted average £/MWkm (J in the example above) is then converted in to an annual figure by multiplying it by the annuity factor.

The final step in calculating the expansion constant is to add a share of the annual transmission overheads (maintenance, rates etc). This is done by multiplying the average weighted cost (J) by the overhead factor.

The overhead and annuitised costs are then summated to give the expansion constant.

Continuing the above example, the final steps in establishing the expansion constant are shown below:

400kV OHL expansion constant calculation	**Ave £/MWkm**
OHL	114.160
Annuitised	7.535
Overhead	2.055
Final	**9.589**

Table A6 – Expansion Calculation

Impact of the Expansion Constant
As the expansion constant represents the unit cost of 400kV overhead line transmission then a change to its value will alter the locational element of TNUoS charges. Those users requiring greatest use of the GB transmission system (i.e. generation located furthest from demand and vice versa) will be most greatly affected. The charts below illustrate the impact of a change of the expansion

constant on 2012/13 TNUoS wider zonal generation and demand tariffs. An increase in the expansion constant can be seen to increase the locational differentials between zones, whilst a reduction in the expansion constant reduces the strength of the locational element.

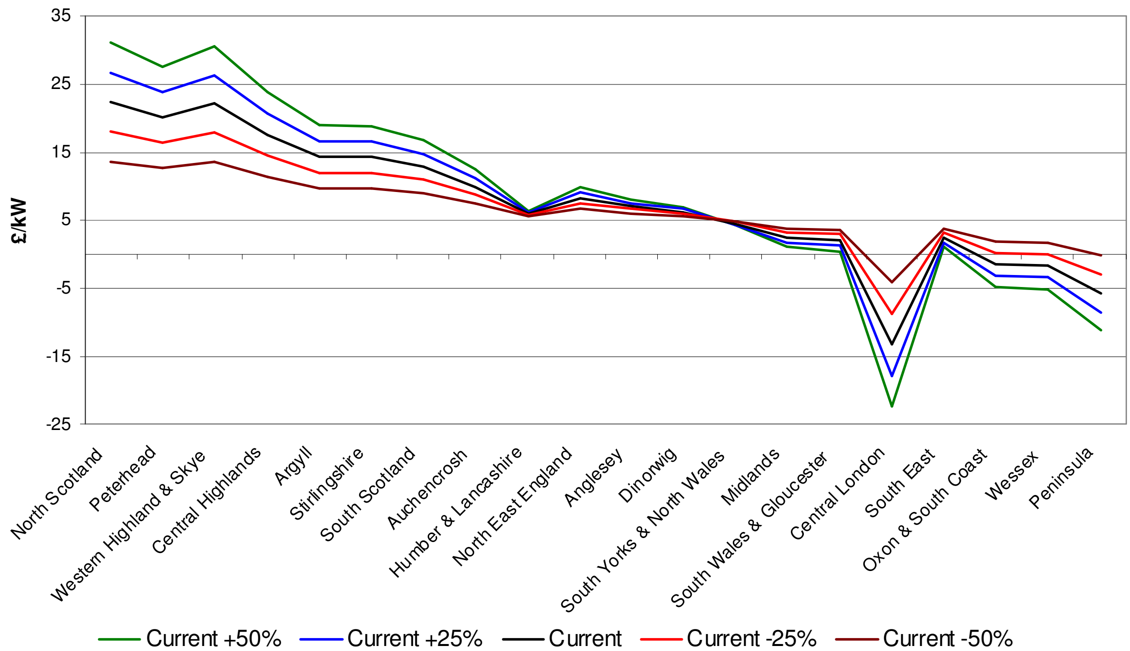

Chart A6 – Illustrative Impact of changing the expansion constant on wider zonal generation tariffs (Note: a +/- 25% change is equivalent to +/-£2.93/MWkm)

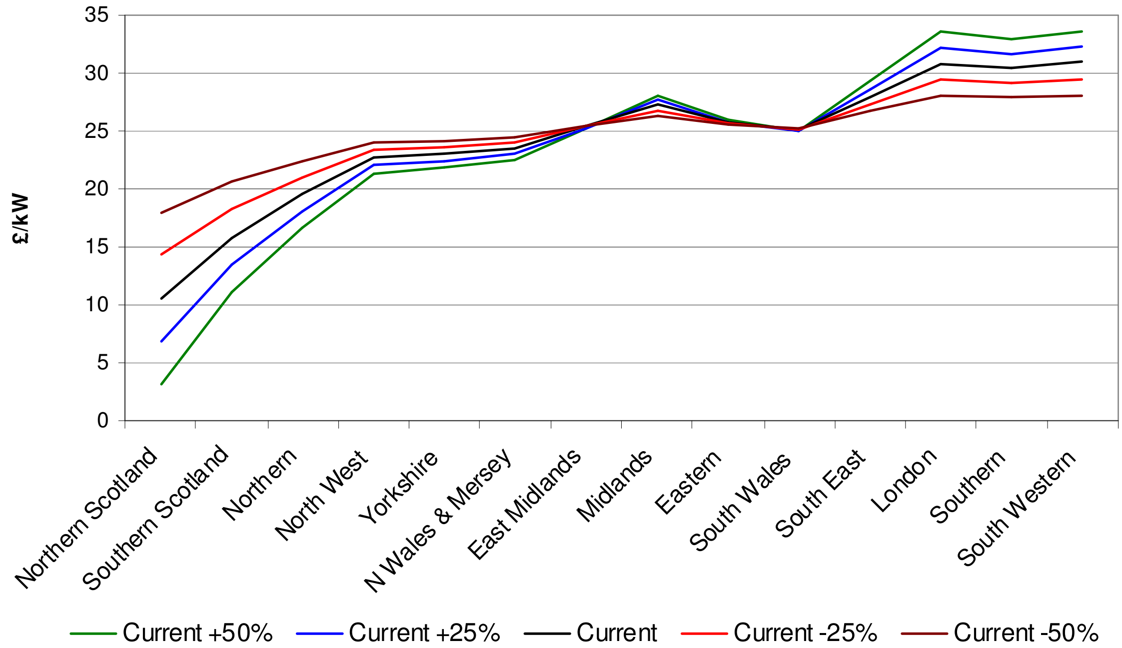

Chart A7 – Illustrative Impact of changing the expansion constant on zonal demand tariffs (Note: a +/- 25% change is equivalent to +/-£2.93/MWkm)

5. The Expansion Factors

The expansion constant describes the annual cost of building 1km of 400kV overhead line together with business overhead costs. The expansion factors describe the relative costs of other types of circuit construction in each onshore TO transmission area. The current expansion factors are shown below.

Type	Voltage	NG	SP	SSE
Cable	400	22.4	22.4	22.4
	275	22.4	22.4	22.4
	132	30.2	30.2	27.8
OHL	400	1.0	1.0	1.0
	275	1.1	1.1	1.1
	132	2.8	2.8	2.2

Table A7 – Current expansion factors

Base onshore expansion factors are calculated by deriving individual expansion constants for the various types of circuit, following the same principles used to calculate the 400kV overhead line expansion constant. The expansion factors are then derived by dividing the calculated expansion constant by the 400kV overhead line constant. The factors are then fixed for the price control period. For example, if 1km of 400kV OHL costs £10 per annum, then 275kV OHL costs £11 per annum (i.e. 10*1.1).

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

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

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

The 400kV onshore circuit expansion factors are applied on a GB basis and reflect the full costs for 400kV cable and overhead lines.

Local onshore circuit tariffs are calculated using local onshore circuit expansion factors. These expansion factors are calculated using the same methodology as the onshore wider expansion factor but without taking into account the proportion of circuit kms that are planned to be uprated. Additionally, the 132kV onshore overhead line circuit expansion factor is sub divided into four more specific expansion factors. This is based upon maximum (winter) circuit continuous rating (MVA) and route construction whether double or single circuit.

Offshore expansion factors are derived from information provided by Offshore Transmission Owners for each offshore circuit. Offshore expansion factors are

Offshore Transmission Owner and circuit specific. They are also reviewed at the start of a new price control period when the expansion constant is reviewed.

All expansion factors are published annually in the Statement of Use of System Charges.[9]

Expansion factors have a similar effect as the expansion constant, in that they impact the locational element of TNUoS charges. However, as they are dependent on both circuit type and voltage, their impact can have more of an impact on specific customers. For example, an increase in cable expansion factors would increase the locational element of TNUoS charges for those users reliant on transmission in urban areas. Similarly, a reduction in 132kV expansion factors would benefit those users making use of 132kV transmission systems.

6. The Locational Security Factor

The transport model calculates the cost of an additional MW of generation or demand at each node assuming an intact transmission system. The transmission system however is highly integrated to ensure that when a network fault occurs, demand is not interrupted. The security factor represents the additional cost of building an integrated transmission system. A single GB average security factor is used - currently 1.8 - since large parts of the network are constructed with double circuits. It is currently reviewed at the start of a new price control period and then fixed for the duration of a price control.

The locational security factor is reviewed on a GB basis through nodal comparison of two DC load flow scenarios in a transport mode. Each scenario has the same generation and demand background but have different network configurations;

1. an intact transmission system
2. a transmission system with a worst case "contingent event" for each transmission node e.g. a single / double circuit faults

This means the model has to be run hundreds of times. The locational security factor is the nodal cost differential between the two modelled scenarios averaged on a GB basis. Chart A8 below shows a sample output of this analysis. The gradient of the best fit line provides the locational security factor.

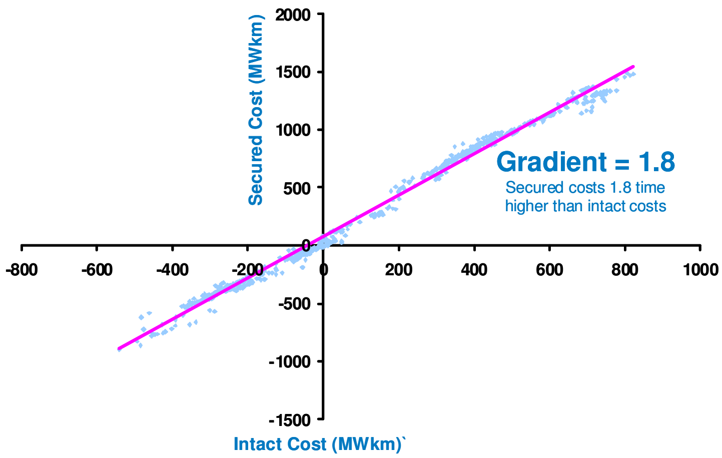

Chart A8 – Illustrative example of locational security factor derivation

Additionally there are a number of local onshore security factors. These are generator specific and are applied to a generator's local onshore circuit. If the loss of any one of the local circuits prevents the export of power from the generator to the MITS then a local security factor of 1.0 is applied. For generation with circuit

[9] Statement of Use of System Charges - April 2012

redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

Specific offshore local security factor (LocalSF) are calculated on an individual basis for each offshore connection. The offshore security factor for single circuits with a single cable will be 1.0 and for multiple circuit connections will be capped at the locational onshore security factor, i.e. currently 1.8.

The locational security factor is used as a multiplier to determine the locational element of TNUoS charges. As it is applied on a global basis, similar to the expansion constant, then it impacts the locational element of TNUoS charges in a similar manner to the expansion constant. As such, an increase in the global security factor will result in a stretching of the locational signal across Great Britain with those users requiring most use of the transmission system seeing an increase in TNUoS charge. This is consistent with the underlying message of such an increase, in that to build a secure transmission system a greater number of assets is required. The reverse is also true, a reduction in the locational security factor will contract the locational element of TNUoS charges.

Generation Charging Zones

The transport model calculates the marginal MWkm cost of transmission infrastructure investment on a nodal basis. For both stability and simplicity, these nodes are assigned to zones with a common unit cost.

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

Generation zones are established via defined criteria at the beginning of each price control period with another review only undertaken in exceptional circumstances. These criteria are as follows;

i.) Zones should contain nodes whose wider marginal costs (as determined from the output from the transport model) are all within +/-£1/kW (nominal prices) across the zone. This means a maximum spread of £2/kW in nominal prices across the zone.

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

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

A common cost for each zone is arrived at through a weighted average of the nodal costs (weightings from generation capacities). The process is driven by initially applying the nodal marginal costs from the transport model onto the appropriate areas of a substation line diagram. Generation nodes are grouped into initial zones using the +/- £1/kW range. All nodes within each zone are then checked to ensure the geographically and electrically proximate criteria have been met using the substation line diagram. The established zones are inspected to ensure the least number of zones are used with minimal change from previously established zonal boundaries. The zonal boundaries are finally confirmed using the demand nodal costs for guidance.

The minimum number of zones, which meet the stated criteria, are used. If there is more than one feasible zonal definition of a certain number of zones, National Grid determine and use the one that best reflects the physical system boundaries.

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

As the review of generation zones is dependent on output data from the transport model and requires both the expansion constant and locational security factor, it cannot be completed until the review and update of the six previously discussed charging parameters has finished.

Impact of generation rezoning on TNUoS tariffs

The impacts of re-zoning are specific generators, and can be difficult to predict. The following illustrative example aims to show why this is the case.

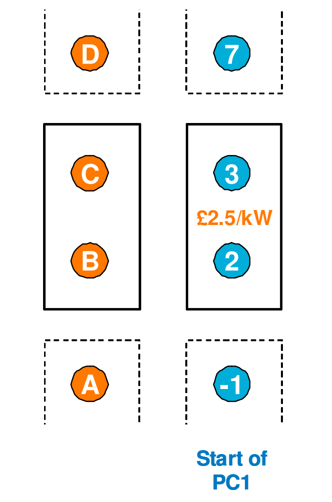

Fig. A1

Let us consider four generators of equal capacity; A-D who are the subject of a TNUoS zoning exercise at the start of price control period PC1. The assessment of nodal £/kW costs gives the results as shown opposite in Fig. A1. As generators B and C are already in a common zone, and their nodal costs are still remain within the £2.00/kW spread they remain as a common zone with a zonal price of £2.5/kW. Generators A and D have nodal prices which both sit outside this range, and therefore remain in separate zones.

During the following price control period, there can be changes to both the generation and demand background as well as to the transmission system. This coupled with the review of charging parameters required at a price control review means that nodal costs can have significantly changed.

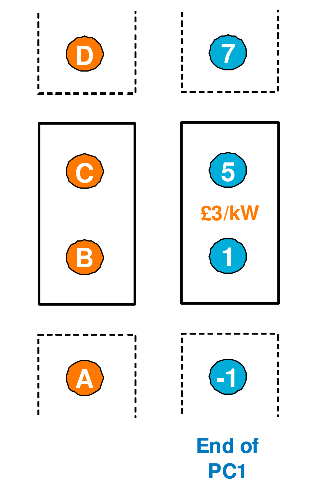

Fig. A2

The situation at the end of PC1 is shown in the Fig. A2 opposite. The nodal cost of generator B has now dropped to £1/kW whilst that of generator C has risen to £5/kW. Their zonal price is now £3/kW.

The next re-zoning happens at the start of PC2. Generators B and C are no longer within the £2/kW spread, but do meet these criteria with other neighbouring generation. As a result, generator B is moved into a zone with generator D and sees an increase in zonal tariff of £3/kW, whilst generator C moves into a zone with generator A and sees a £3/kW reduction in its zonal tariff.

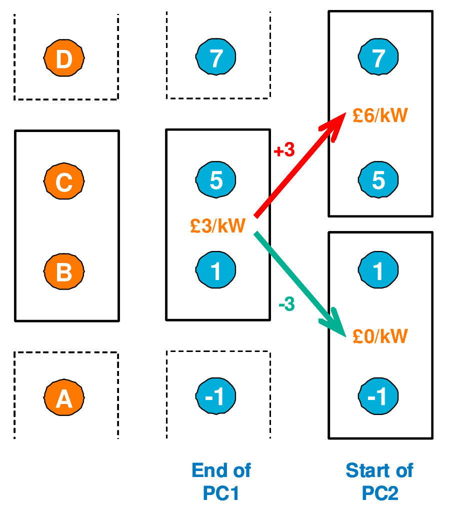

Fig. A3

Annex 8 – Supporting tariff information

The following tables provide the tariff information underpinning the charts shown in Annex 6.

Table A9 – Generation Tariff Information

Zone	Generation Tariffs (£/kW)		
	12/13	**13/14**	**13/14**
Updates	*Current tariffs*	*G&D Only*	*G&D + EC&EF**
1	21.96	26.24	28.40
2	20.11	23.41	24.99
3	22.05	25.37	27.27
4	17.56	21.45	22.35
5	14.19	17.48	17.90
6	14.23	16.76	17.18
7	12.79	15.10	15.23
8	10.50	15.76	15.98
9	6.08	7.13	7.12
10	8.43	9.47	9.16
11	7.10	8.45	8.67
12	6.36	7.68	7.84
13	4.61	5.10	5.20
14	2.39	2.80	2.76

* Central case

Table A10 –Demand Tariff Information

Zone	Half-Hourly Demand (HH) £/kW			Non Half-Hourly Demand (NHH) p/kWh		
	12/13	**13/14**	**13/14**	**12/13**	**13/14**	**13/14**
Updates	*Current tariffs*	*G&D Only*	*G&D + EC&EF*	*Current tariffs*	*G&D Only*	*G&D + EC&EF**
1	10.57	13.87	12.97	1.46	1.91	1.79
2	15.84	19.63	19.52	2.24	2.77	2.76
3	19.50	25.19	25.69	2.70	3.49	3.55
4	22.67	28.22	28.48	3.29	4.09	4.13
5	23.01	28.88	29.02	3.19	4.01	4.03
6	23.47	29.15	29.06	3.37	4.18	4.17
7	25.28	31.83	32.05	3.58	4.51	4.54
8	27.19	33.00	33.09	3.91	4.75	4.76
9	25.79	32.89	33.38	3.61	4.61	4.67
10	25.09	30.81	31.30	3.34	4.11	4.17
11	28.08	36.41	36.10	3.96	5.14	5.10
12	31.01	39.30	38.11	4.15	5.25	5.10
13	30.45	37.50	37.37	4.32	5.32	5.30
14	30.90	37.99	38.34	4.20	5.17	5.22

* Central case