CMP242

'Charging arrangements for interlinked offshore transmission solutions connecting to a single onshore substation'

CMP242 aims to ensure that there are appropriate charging arrangements for offshore transmission network where two offshore substations, connected to the same onshore substation, have a transmission connection (interlink) between them offshore.

Published on: 5th November 2015
Length of Consultation: 15 Working days
Responses by: 26th November 2015

This document contains the discussion and conclusions of the Workgroup which formed in April 2015 to develop and assess the proposal.

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

The Workgroup concludes:
That the original, WACM1 and WACM2 all better facilitate the CUSC objectives than the CUSC baseline. Half of the Workgroup concluded that the Original Proposal best facilitates the CUSC objectives and should be implemented. Half of the Workgroup concluded that WACM1 best facilitates the CUSC objectives and should be implemented.

High Impact:
Offshore Generators

> **Low Impact:**
> All other parties liable for TNUoS

Contents

Any Questions?

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About this document

The purpose of this document is to consult on CMP242 with CUSC Parties and other interested industry members. Representations received in response to this consultation document will be included within the Final CUSC Modification Report which will be furnished to the Authority for their decision.

Document Control

Version	Date	Author	Change Reference
1.0	5th November	Code Administrator	Code Administrator Consultation to Industry

1 Summary

1.1 This document describes the Original CMP242 proposal, summarises the deliberations of the Workgroup, includes responses to the Workgroup consultation.

1.2 CMP242 was proposed by National Grid Electricity Transmission plc and submitted to the CUSC Modifications Panel for their consideration on 27th March 2015.

1.3 The CMP242 proposal aims to ensure that there are appropriate charging arrangements within the CUSC for offshore transmission networks that link two, or more, offshore substations (used by offshore generators) which are connected to the same onshore substation; i.e. are interlinked offshore. The interlinks allow generators connected to either offshore substation to export some (or all) of their output to shore via either generator's circuits to shore (depending on the capacity available on the circuits and interlink). At present the charging methodology for offshore transmission considers only radial circuits to shore and therefore does not take account of any interlinks that may be built. This modification does not cover the situation where increased onshore capacity would be provided or where the interlink would influence the design of onshore reinforcement works; i.e. an integrated offshore network.

1.4 Following the workgroup discussions, as summarised in this report, the Original Proposal and two Workgroup Alternative CUSC Modifications (WACMs) were proposed:

   a. **Original Proposal:** The costs of the interlink circuit are shared between the generators, based on a **formula** representing the opportunity each generator has to use the interlink in the event of a single fault;

   b. **WACM1:** The **formula** is the same as the Original Proposal, however, there is an alternative for parties to **negotiate** how the costs of the interlink circuit are shared between the generators to take in to account other factors.

   c. **WACM2:** The costs of the interlink circuit are shared between the generators as determined by **negotiation** between the generators only.

1.5 At the final Workgroup meeting, Workgroup members voted on the Original Proposal and the two WACMs: Half of the Workgroup concluded that the Original Proposal better facilitates the CUSC objectives and should be implemented. Half of the Workgroup concluded that WACM1 better facilitates the CUSC objectives and should be implemented.

1.6 The CMP242 Workgroup Report was presented to the CUSC Panel on 30th October 2015. The Panel agreed that the CMP242 had met their Terms of Reference and that CMP242 could proceed to Code Administrator Consultation.

1.7 This Code Administrator Consultation and supporting material has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid website.

2 Background

2.1 The current transmission charging methodology, as defined in Section 14 of the CUSC[1], defines 'the charges' to be paid by generators associated with their offshore substation and offshore circuits that they use. These arrangements have been designed around the prevailing design arrangements for offshore transmission, specifically radial circuits connecting offshore substations to onshore substations.

2.2 A number of developers of offshore generation are now planning the construction of a transmission cable (or 'interlink') linking offshore substations between some of their projects that connect to a common (onshore) substation. It is also possible that an interlink is required where the two (separate) developments are unrelated commercially / corporately. The intention is for this interlink to be held in open standby unless the cable to shore associated with one of the offshore substations becomes unavailable (through a fault or an outage). The interlink would then be switched in to allow some (or all) of the energy to reach the shore from either generator subject to available capacity on the remaining cable.

2.3 The primary reason for considering an interlink in the design of an offshore network is that it offers an alternative electrical route to shore in the event of a fault on a generator's main cable. The interlink is viewed as a more cost effective alternative to each generator being served by multiple circuits directly due to the high costs of offshore transmission compared to onshore transmission.

2.4 This Code Administrator Consultation considers explicitly the case of two and three offshore generators / substations, but also sets principles for configurations with more. The Workgroup discussions tended (for simplicity) to focus on the most likely scenario, namely the two offshore generator / substation example; however, the three offshore generator / substation example was also considered. The situation for three offshore generators / substations is illustrated in Figure 1.
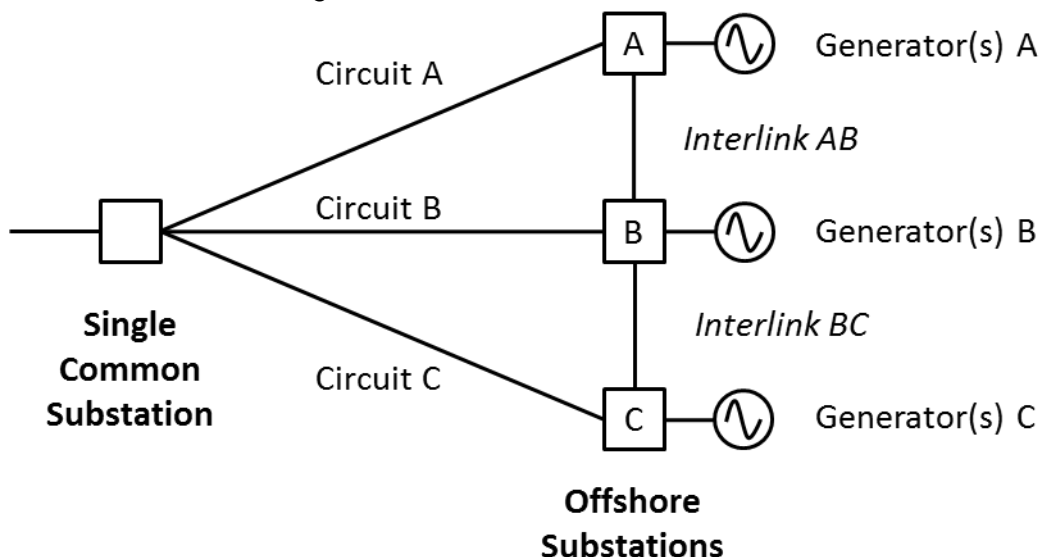
Figure 1: *The case of three offshore substations, connected to a single substation, interlinked with transmission circuits.*

2.5 Where an interlink is designed / built between offshore projects, such interlinks will provide additional security to each generator, as they provide an alternative transmission route to shore, without the high costs of building an additional radial circuit to shore. A generator's main radial circuits to shore will continue to be scaled accordingly to the standard offshore

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

design and in particular will neither be smaller or significantly larger than required for the associated offshore generator. Overall, an interlink solution in some cases may provide an economic 'insurance premium' for the generator, whereas a second cable to shore would be uneconomic for that single generator.

2.6   The standard design for an offshore substation is for a single busbar, to which the generator is connected via a circuit breaker, and the circuit to the onshore substation via a transformer and circuit breaker. To accommodate an interlink, an additional bay or bays (shown in red in Figure 2 below) may be required on the busbar along with additional circuit breakers and associated equipment to connect a circuit to the other offshore substation.

2.7   It was noted by the Workgroup that it may be possible to include an interlink to an existing offshore substation provided there was sufficient space on the offshore substation platform for the necessary bay on the busbar and the associated equipment. However, given the construction costs offshore, this situation is deemed unlikely as the platform is likely to be designed / sized for the initial (non-interlink) situation.
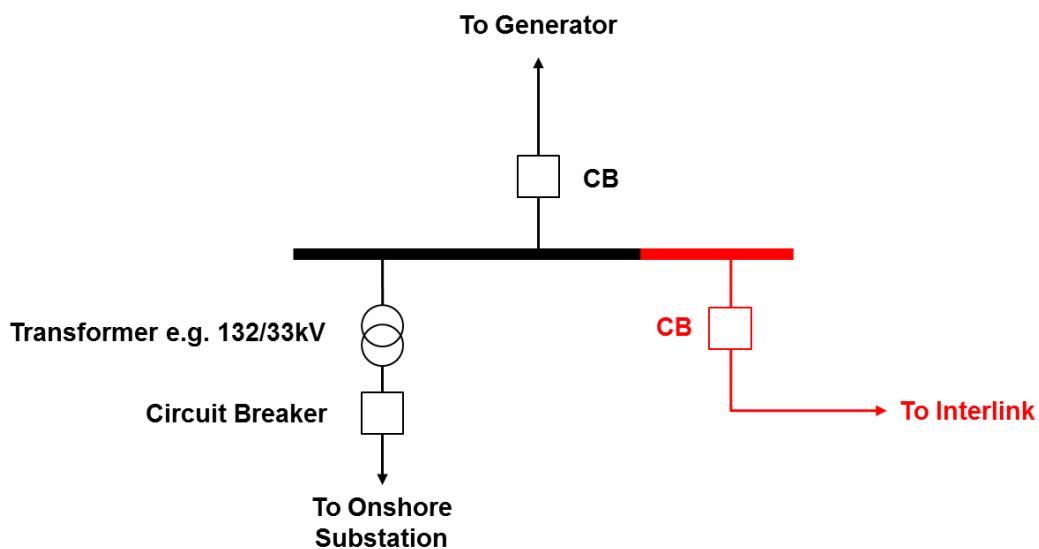
Figure 2: *Indicative offshore substation layout showing the additional single busbar with an additional bay and equipment (shown in red) to facilitate the interlink*

2.8   At present, similar low voltage cables exist for a number of offshore generators, linking offshore substations; however, these have remained as generator owned assets rather than transferring to the offshore transmission owner (OFTO). These cables typically exist to provide back-up supplies to a platform in the event of a fault rather than as an export route. As generator owned assets these assets are not covered in the CUSC charging methodology.

2.9   The current charging methodology within Section 14 of the CUSC does not provide a cost reflective charge for offshore transmission solutions provided by the OFTO(s) that include interlinked offshore substations connecting to a common onshore substation, as the cost of providing the additional link would not be reflected in the local circuit charge, or any other component of the charge. The CMP242 proposal seeks to address this defect.

3 Summary of Workgroup Discussions

3.1 The Workgroup discussions over the six Workgroup meetings are summarised in this section. Discussions have been grouped into themes, rather than being presented chronologically.

3.2 Starting with the key assumptions on which the Workgroup based its discussions, the following themes were discussed:

- Should a generator be able to opt-out of paying for and using an interlink?
- Which elements of a generator's charges should change to account for the interlink?
- Options for apportioning interlink costs between generators
- Formula for determining proportions of interlink costs for each generator
- Exploration of Alternative Parameters
- The situation of a radial connection with multiple transmission circuits
- Formula for apportionment
- Commissioning, decommissioning and TEC Changes
- Priority access for generators on their "own" transmission circuit
- Other impacts on the OFTO regime

3.3 The key summary of each of these themes is detailed in

3.4 Table **1** below.

Key Theme	Section Start	Headline Conclusion
Should a generator be able to opt-out of paying for and using an interlink?	3.6	The Workgroup concluded that the Original Proposal would be structured in such a way that it applied only to (i) parties when an interlink was included in the design phase of their project(s), and (ii) in situation where an existing generator agreed to the interlink.
Which elements of a generator's charges should change to account for the interlink?	3.21	The Workgroup concluded that there should be no changes to the methodology for charging for offshore substations, or a charge to reflect the use of another circuit beyond a generator's main circuit(s). Only the local circuit tariff for each generator would be updated to reflect the costs associated with the interlink.
Options for apportioning interlink costs between generators	3.30	The workgroup concluded that there were three options for how the costs associated with an interlink could be apportioned between those benefits from the interlink: • Apportionment determined by a formula only; • Apportionment determined by formula with negotiation as an alternative; • Apportionment determined by negotiation only.

Key Theme	Section Start	Headline Conclusion
Formula for determining proportions of interlink costs for each generator	3.41	The Workgroup concluded on a formula which shares the costs of the interlink between the generators based on each how much additional transmission capacity (MW) a generator has to shore using the interlink, using the following parameters: • A measure of the likely output of the generator (the generator's TEC multiplied by its Annual Load Factor) • A measure of the likely capacity available on the other main offshore transmission circuit(s) - the capacity of each of the other main circuit(s) to shore less the other generator's TEC multiplied by its Annual Load Factor; • The capacity of, where appropriate, each interlink
Exploration of Alternative Parameters	3.55	The Workgroup assessed other parameters not included in the model (including load, load profile, volatility, correlation, seasonality, and fault likelihood) and concluded that the Annual Load Factor provided an appropriate proxy for output, given that TNUoS is an annual charge.
The situation of a radial connection with multiple transmission circuits	3.84	It was noted that the situation of having multiple circuits to shore and an interlink was within scope. It was deemed appropriate to only consider a single circuit fault, when considering opportunity a generator has to use the interlink. This maintains consistency with the onshore regime.
Formula for apportionment	3.90	Based on the discussions held, a formula was created based on discussion earlier in this report.
Commissioning, decommissioning and TEC Changes	3.94	It was agreed that prior to a generator commissioning, or after a generator decommissioning, their share of the interlink cost could be socialised rather than being paid for by the remaining generators, as the interlink had been designed and costed as if they were present. During operational life, it was agreed that the maximum value of TEC should be used in the calculation of proportions to avoid one generator paying due to another generator reducing their TEC.
Priority access for generators on their "own" transmission circuit	3.106	The workgroup held a discussion, but did not foresee any concerns around the assumption that *priority for export will be given to the generator connected via the remaining main circuit (i.e. the cable which directly connects their asset to shore), and the other generator may need to reduce their output if they wish to use the interlink to export via the remaining main circuit, unless there is a commercial arrangement (outside the CUSC) between the parties.*
Other impacts on the OFTO regime	3.112	The Workgroup noted some potential impacts on the OFTO regime and highlighted these to the Authority.

Table 1: *Summary of the headline conclusions in each area of investigation.*

Key Assumptions

3.5   The discussions held by the Workgroup and the views presented in this report are based on a number of key assumptions:

- The interlink will normally be switched out of use (i.e. held in open standby). If a fault or outage occurs on one of the radial circuits connecting a generator to the shore, the interlink would need to be switched in, allowing export of some or all energy from the otherwise disconnected generator.
- Priority for export will be given to the generator connected via the remaining main circuit (i.e. the cable which directly connects their asset to shore), and the other generator may need to reduce their output if they wish to use the interlink to export via the remaining main circuit, unless there is a commercial arrangement (outside the CUSC) between the parties. (This assumption is discussed in further detail on page 32). This priority will be reflected in each Bilateral Connection Agreement (BCA).
- Main radial circuits from the offshore substations to the common substation will continue to be scaled accordingly to the standard offshore design (defined in the SQSS[2]), and in particular will neither be smaller or significantly larger than required for the main associated offshore generator.
- The interlink will be an AC cable. Due to the expected distances between the two offshore substations, an HVDC link would not be considered economic[3].
- From a system operation perspective, the interlink can be used in either direction to export energy from either offshore generator as required depending on the situation.
- Any changes to the charging methodology arising from CMP242 will apply to both developer-build and OFTO-build situations.
- The methodology will apply to situations where one or more generator has a double or multiple circuit connection to shore.
- The methodology will apply to all offshore generation technology types, although the analysis has been based on existing offshore windfarms.

Should a generator be able to opt-out of paying for and using an interlink?

3.6   The question of whether a generator should be able to opt-out of paying for and using an interlink was discussed by the Workgroup. It was noted that having an 'opt-out' is related to timing of the installation of the interlink compared to that of the other generators.

3.7   It was assumed that an interlink would be included in a design at one of two stages, either:

- An interlink is proposed during the development phase for all generators concerned; or
- An interlink is planned when one generator is already built or financially committed but the other generator(s) is in the development phase.

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[2]   National Electricity Transmission System Security and Quality of Supply Standard.

[3]   Indicative estimates provided to the Workgroup indicate that a 600MW capacity cable, HVDC cables would become preferred over AC at a circuit length of around 130-150km. As an interlink connects two offshore substations connected to the same onshore substation, it is assumed the distance between the two offshore substations will be less than this crossover value.

An interlink is proposed during the development phase for all generators

3.8   It was agreed by the Workgroup that the majority of possible interlinks are likely to fall into the category of being developed when both generators are under development; i.e. neither has been built or financially committed. This is based on the requirement for the offshore substations needing to be sized appropriately, and given the high-cost of offshore works it is unlikely that offshore substations would be significantly oversized to allow for future expansion to accommodate an interlink capability.

3.9   The Workgroup also agreed it was appropriate for the costs of the interlink to be shared between the relevant offshore generators (using an appropriate methodology), and that all those generators who gain a right to use the interlink should be subject to an appropriate charge for doing so. This is analogous to the onshore scenario where charges are set to reflect the transmission network and how a generator can access and use that transmission network.

3.10   The related issue of whether the interlink may make a project economically unviable for one or more of the generators was discussed, and it was agreed that in this situation the overall project proposal would not be considered economic and efficient, and that an alternative solution would be needed before it could proceed. Such an alternative solution might involve the removal of the interlink circuit at the design / development stage.

An interlink is planned when one generator is already built or financially committed

3.11   The Workgroup noted that the situation of one generator already existing (or being financially committed) prior to an interlink being planned is less likely to occur but that nonetheless it should be considered further.

3.12   In this situation, it is noted that there are the two options for the existing generator:

   a. The OFTO(s) and SO determine that it is efficient to build the interlink, and the existing generator incurs a share of the cost of the interlink (as does the other, to be developed / built, generator) and has the right to use it (as does the other generator); or

   b. The OFTO(s) and SO determine that it is efficient to build the interlink, however, the existing generator **chooses not** to pay for the interlink, and so **has no right to use it**. The other (to be developed / built) generator would be able to use the interlink (exclusively) and would pay all the associated charge for the interlink.

3.13   Option (a) mirrors the current onshore situation associated with onshore reinforcement works, although it was noted that the nature (and likely substantially higher cost) of offshore interlinks compared to similar onshore situations may warrant a difference in treatment. Option (b) permits an 'opt-out' of using an interlink for an existing generator, allowing them to avoid potentially significant additional charges which may cause them to become economically unviable after they have financially committed / built their asset. There was a view from some Workgroup members that having the ability to 'opt-out' of paying (and using) the interlink should be an option available to the committed generator to avoid that generator, in this situation, being left with a stranded (generation) asset through no fault of their own.

3.14   The National Grid representative noted that as the interlink would need to be manually switched in when required, it would be possible to operate the interlink in such a way that it would only operate mono-directionally benefiting only the one generator paying for it. It was further noted that, putting aside any commercial arrangement, such a mono-directional operation may not be the most economic and efficient for the system as a whole, as it could potentially mean that generation could not export even though there was circuit capacity available for them to do so; although Workgroup members noted that that was that generator's choice so to do. In the case of an enduring fault on a main circuit, this situation

may be harder to justify, given that end consumers pay for all charges through their bills; although Workgroup members noted that in the event of a stranded generation asset it would not be end consumers but the shareholders of that generator who would pay the costs incurred.

3.15 In common with the 'during development phase' scenario, it was noted that in this scenario if an existing generator were to be rendered economically unviable by the installing of an interlink then this is not likely to be an overall efficient and economic solution, and therefore it is unlikely to be built.

3.16 Table 2 summarises the pros and cons of the options when one generator is already existing (or financially committed) and an interlink is subsequently planned.

Option		Pros	Cons
(a)	Both generators have a right to use the interlink and pay the associated charge	Aligns onshore and offshore charging regimes Allows maximum flexibility for the SO and generators	The size / value of offshore generators, and the costs for transmission are substantially different compared to onshore. Risk that existing generator is rendered economically unviable with the extra cost of interlink – leads to higher regulatory risk, leading to higher cost for consumers and a reduction in competition in generation (as that generator exits the market).
(b)	One generator (X) chooses to have no rights and so they incur no cost for the interlink. The other generator (Y) bears all the costs of the interlink and has exclusive rights to use the interlink.	Removes risk that generator (X) is rendered economically unviable by the action of another party (generator Y) or OFTO(s) and SO. Reduces regulatory risk and facilitates competition in generation.	Different charging regime offshore to onshore. Generator (X) could, by not paying for the interlink, be limiting an overall efficient build. SO potentially constrained by contractual obligations, and limited ability to operate system efficiently. In an enduring fault scenario, may have a generator (X) disconnected even though a transmission circuits exists to connect it.

Table 2: *Summary of pros and cons for whether an existing generator should or should not be able to opt-out of paying for using an interlink.*

3.17 The Workgroup noted that a consequence of a generator choosing option (b) could be, at a later date, that the generator may choose to pay for and have the use of the interlink. A Workgroup member believed this would likely lead to a behaviour where developers / generators do not enter into an agreement until they are forced to do so; i.e. their radial circuit to onshore fails/faults. The Workgroup agreed to consult on how a generator, who having initially opted-out, and later opts-in should be treated. In particular, should the generator be subject to any retrospective charges.

3.18 The Workgroup agreed that in practice option (a) was the preferred scenario; however, some Workgroup members believed that option (b) should remain available for some situations to avoid financially stranding an existing generator. The Workgroup agreed to seek industry views through the Workgroup Consultation on whether an existing generator should be able to opt-out of paying the charges and the ability to use an interlink, if an interlink was proposed to be installed at a later date after their financial close.

3.19 Overall there was not a clear consensus from the respondents in the Workgroup Consultation on these two issues. Workgroup Consultation responses are summarised in Section 8 of this Report.

Workgroup Conclusions

3.20 The Proposer stated that the Original Proposal would be structured in such a way that it applied only to (i) parties when an interlink was included in the design phase of their project(s), and (ii) in situations where an existing generator agreed to the interlink. Given

that it was deemed unlikely that an existing OFTO/generator would install an interlink later due to the lack of space in their offshore substation platform, this was deemed a pragmatic approach by the Workgroup without introducing an opt-out or opt-in clause.

Which elements of a generator's charges should change to account for the interlink?

3.21 At present the current offshore charging methodology is designed around radial circuits, rather than an integrated offshore transmission network. Details of the current offshore charging regime are detailed in Annex 5 of this report. An offshore generator is liable for a TNUoS tariff composed of three key elements:

- offshore local substation tariff;
- offshore local circuit tariff; and
- wider tariff.

In addition, if the onshore substation is connected to the MITS (Main Interconnected Transmission System) by a local transmission circuit or a distribution network, additional elements will be added to the tariff. These additional elements are not affected by the interlink.
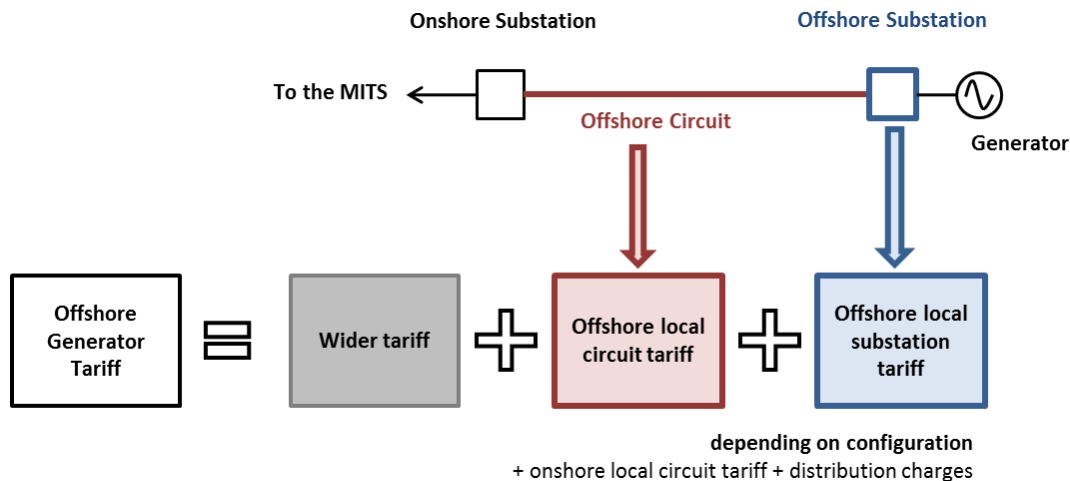

Figure 3: *Elements of an offshore generator's TNUoS Tariff.*

Local Offshore Substation Charge

3.22 The GB charging methodology set out in Section 14 of the CUSC provides that offshore and onshore generators only pay a substation charge for the first local substation that a generator is connected to. In the case of the existing radial offshore design, this means that a generator pays a charge for the offshore substation, but no charge for the associated onshore substation.

3.23 In a configuration involving an interlink (as detailed in Figure 4), additional substation equipment is required to be installed at the offshore substations of each generator. It was noted that if Generator A should pay for part of the interlink equipment in substation B and vice-versa, then these two costs may net off as the equipment should be broadly similar at either end. At least one Workgroup member noted that any discrepancy could be addressed by offering parties the ability to negotiate their split of costs.
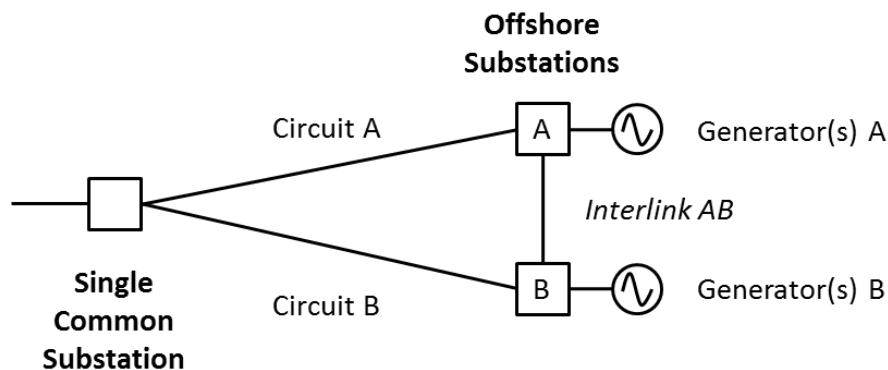
Figure 4: *A configuration with two generators and one interlink.*

3.24 The Workgroup agreed that there was no need to change the way in which offshore substation charges are levied as a result of the interlink and the CMP242 proposal. Each generator would continue to pay a substation charge based on all the items at the first offshore substation, including those items required for the interlink circuit (e.g. additional busbar bay, circuit breaker).

Local Offshore Circuit Charge
Costs associated with the interlink

3.25 A broad discussion was held on the advantages to the generator of having an additional route to shore via an interlink. The Workgroup agreed it was appropriate for the costs of the interlink to be shared between the offshore generators who benefit from it, as it was designed and developed for their use. Page 14 onwards considers the options for how to apportion the costs between the generators.

3.26 For offshore generators with a single radial circuit to shore, designed to the standard offshore design as detailed in the SQSS, details are placed in 'Clause 10' of the Bilateral Connection Agreements specifying what the Allowed Interruptions are. The detail of Clause 10 will need to be considered for individual generators where an alternative route to shore is potentially available via an interlink.

Costs associated with capacity on the other main circuit

3.27 For a generator (A) with an interlink, there is potentially some capacity available on the other generator's (B) main circuit to be used in the event of a fault or outage on their (A) main circuit. The Workgroup considered whether a charge should be levied for the opportunity and redundancy that this capacity may provide. The Workgroup noted two high-level options.

- do not reflect the cost of the other main circuit in a generator's local circuit charge, or
- reflect the cost, using some mechanism, of the additional redundancy provided via the other main circuit.

3.28 The Workgroup considered that there should be no charge levied to the generator for the cost of the other radial circuit which may be used in the case of an interlink. This position is different to part (iii) of the Original modification proposal (see Annex 1), but has been based on the following reasons:

- If Generator A pays for part of Generator B's main circuit, and vice versa, the overall effect is likely to net off and have very little difference to the overall charge, but add significant complexity to the charging methodology.

- The main circuit is sized appropriately for the export of the associated generator and any additional capacity provided by that main circuit to the other generator is primarily a feature of that main circuit being more efficient to install as a standard sized cable.
- The current offshore charging methodology does not charge for non-firm access.
- The interlink is only used in the situation of faults or outages of a main circuit and it is not capacity that can be guaranteed.
- The charging methodology is designed to be cost reflective not cost absolute. It was felt that the current arrangement plus the cost of the interlink are reflective of the costs associated with the offshore network, without adding additional complexity.
- The specific situation of one or more generators having multiple circuits to shore is covered on Page 28.

3.29 The Workgroup consulted on this matter, and there were no views expressed to change the conclusions of the Workgroup. Therefore, the Original Proposal is updated to reflect that no charge would be made for an offshore generator's use of another radial circuit via the interlink.

Options for apportioning interlink costs between generators

3.30 The Workgroup concluded that there were two principles that should be applied in apportioning interlink costs between generators who have a benefit from an interlink.

3.31 Firstly, the CUSC charging methodology could be amended to specify how any interlink costs would be shared between generators based on some appropriate parameters (see page 15). Secondly, the CUSC could provide for the relevant generator parties to negotiate their proportions of the interlink costs and notify these to the SO for use in the charging calculation.

3.32 Providing for the specification of interlink cost sharing within the charging methodology in the CUSC is the closest to the current structure of the charging methodology. However, the Workgroup considered the option of allowing the negotiation of the apportionment of the interlink costs between the affected generator parties, but noted that a 'fall-back' of having an arrangement in the charging methodology could be required in the CUSC in the event that the parties could not agree on the apportionment of the costs of any interlink.

3.33 The Workgroup sought views on this from the industry in its consultation. Overall there was agreement that permitting negotiation with a fall-back arrangement in the CUSC charging methodology was a valid approach. Moreover, the Workgroup noted there are potentially parameters which could not be included in a formula within the CUSC charging methodology, which could have an impact on how much one generator can use an interlink. It was also noted that often parties are in the best place to set the proportion of charges they will be paying, as they have the most up-to-date commercial information, and can therefore either set charges through negotiation or vary the result of a formula.

3.34 As a result of the discussions and consultation responses, the Workgroup decided to proceed with three options:
    i.   Apportionment determined by a **formula only**;
    ii.   Apportionment determined by **formula with negotiation as an alternative**;
    iii.   Apportionment determined by **negotiation only**.

3.35 These three options would become the Original Proposal, WACM1 and WACM2 respectively (see sections 4 and 5 of this report).

3.36 Under all three options parties would also be able to undertake bilateral negotiation on a commercial basis outside of the CUSC charging methodology. Under option (ii) they would have the option of adjusting the proportion charged to each generator as part of their TNUoS bill before they receive the invoice from the SO. Under option (iii) it is necessary for parties to agree before the SO can issue them with their TNUoS invoice. One Workgroup member noted that this approach of negotiation outside the CUSC charging methodology may provide more flexibility in how costs can be shared between the generators than can be provided within the methodology.

Dispute resolution

3.37 The form of negotiation proposed by the Workgroup requires there to be dispute resolution; particularly in the case of option (iii), where a value for the apportionment needs to be provided to the SO to allow them to set an appropriate charge.

3.38 A form of negotiation using the other dispute procedure in the CUSC has been proposed. This is proposed for the following reasons: failure of users to agree to proportions to apportioning costs between them is an 'Other dispute' under the CUSC as it does not comply with the definition of charging dispute as defined as:

> 7.2   … any dispute or difference between CUSC Parties of whatever nature howsoever arising under, out of or in connection with:-
>
> 7.2.1   whether Connection and/or Use of System Charges have been applied and/or calculated in accordance with the Charging Statements (including in all cases whether the dispute or difference does arise under, out of or in connection with such issues and therefore falls within this Paragraph 7.2.1) utilising the Authority's role under section 7 of the Act (a "Charging Dispute") shall be resolved in accordance with Paragraph 7.3;

3.39 In particular, when a negotiation is required, there will not be a result of a methodology, the application of which can be contested.

3.40 The reason for using the Authority as the point of referral rather than the Electricity Arbitration Association is consistent with an approach taken in 'Schedule 2 Exhibit 3A - Offshore Construction Agreement'[4] of the CUSC. In addition the workgroup felt that the Authority would be better placed to make such a decision compared to the Electricity Arbitration Association, as the Authority was independent of any party involved in an interlink. The Electricity Arbitration Association as defined in the CUSC references the following definition in the Glossary and Definitions of the Grid Code[5] as:

> **Electricity Supply Industry Arbitration Association:** The unincorporated members' club of that name formed inter alia to promote the efficient and economic operation of the procedure for the resolution of disputes within the electricity supply industry by means of arbitration or otherwise in accordance with its arbitration rules.

Formula for determining proportions of interlink costs for each generator

3.41 The Workgroup noted that it would be necessary to determine a formula by which interlink costs could be apportioned between generators under one of the options proposed (see 3.34). This would need to be based on appropriate parameters of the transmission network, each generator and potentially the advantage each generator gains from the interlink. The

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applicable parameters of the offshore transmission network and the generators are illustrated in Figure 5.
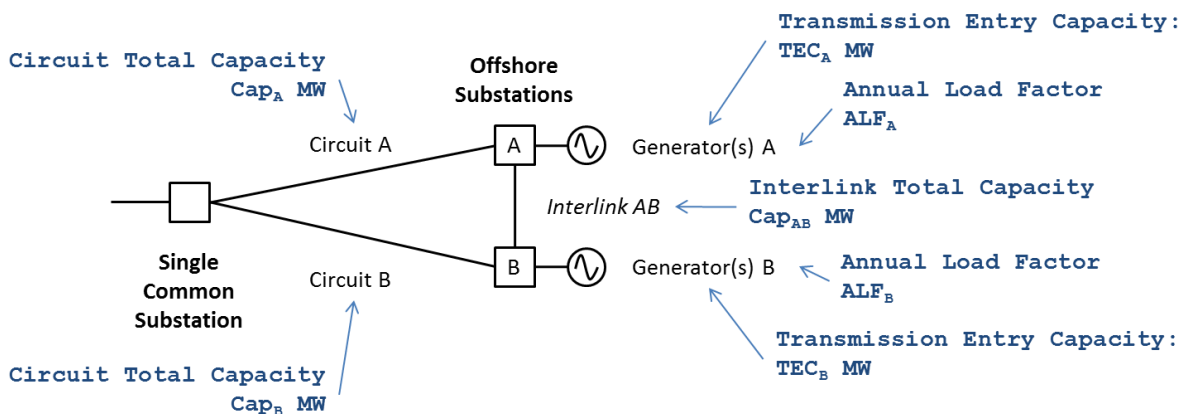
Figure 5: *The Case of two offshore generators connected by an interlink, with the technical parameters of the network and generators highlighted in blue.*

3.42 A generator has **Transmission Entry Capacity (TEC)**. The quantity of TEC has two primary functions – it is the maximum power in MW that a generator may export on to the transmission network, and secondly is the amount they are charged TNUoS based upon. (A standard TNUoS calculation is TEC (MW) × Tariff (£/kW) × 1000). A generator has firm access up to their TEC capacity on their offshore main circuit and, in the case of a standard (single radial circuit) offshore design, no firm capacity in the event of a single fault.

3.43 The transmission circuits to shore each have a **circuit rating**, above which they should not be operated. This rating specifies the maximum power in MW that can flow along that circuit. These are referred to here as the circuit capacities or 'Cap'. Due to the use of standard cable sizes, there may oversizing of the cable compared to the generator's actual contracted (MW) level of TEC; this could result in created 'firm spare capacity'. The capacity on the offshore transmission cable(s) to shore will always be equal to or greater than the TEC of the generator(s) connected to it.

3.44 In addition to this 'firm spare capacity' there may be 'non-firm spare capacity' as with offshore wind farms and other intermittent generation, a generator will often be operating below their contracted TEC (MW) level, meaning theoretically (but not contractually) there is spare (but contractually non-firm) export capacity available on the associated main circuit (the parameters associated with the output of offshore generation is explored on Page 20). It was noted that there is the concept of the **Annual Load Factor (ALF)** introduced into the CUSC under CMP213, which provides a measure of the generator's output over a five year period compared to their contracted TEC. This might be able to be used to apportion benefit and hence costs associated with any offshore interlink.

3.45 The Workgroup noted that this spare capacity on the main cable of one generator A could provide additional transmission capacity to another generator B via an interlink. Some of this spare capacity would always be available (firm) relating to spare capacity on the circuit, and some would be available if the other generator A (whose main cable it was) is operating below their level of contracted TEC (non-firm). The concept of using the Annual Load Factor (ALF) to give a measure of the average non-firm access was suggested. It was noted that given the geographic proximity of the two offshore generators (and that they were likely to be, at least initially, all windfarms) their ALFs are likely to be very similar. Only if there were different offshore generation technologies at the two substations are their ALFs likely to be significantly different.

3.46 The appropriateness of the Annual Load Factor as a proxy for annual output and potential other parameters which have not been included in this model are explored on Page 27.

3.47 Eight initial options for apportioning the interlink costs between each generator were developed by the Workgroup ahead of the Workgroup Consultation. Each of the options, how they score against a number of criteria, and the Workgroup's view *at the point of Workgroup Consultation* are summarised in Table 3.

3.48 The mathematical definitions for all of the situations can be found in Annex 6, as they were included in the Workgroup Consultation, for the situation of a single interlink between two offshore generators / substations.

3.49 Furthermore, respondents to the Workgroup Consultation also noted that they felt the CUSC charging methodology should be expanded to cover the situation of more than one interlink; i.e. multiple offshore generators / substations. The Workgroup agreed to refine the preferred methodology approach and extend it to more than one interlink situation.

Apportionment Option	Description	Areas of concern for the Workgroup						Workgroup's view to proceed
		Reflect generator size	Reflect interlink size	Reflect capacity to shore	Reflect different generator load factors	Fully defined	Unaffected by changes to TEC	
i. Equal Split	Generators pay an equal share for the interlink, regardless of circuit capacity or TEC.	No	No	No	No	Yes	Yes	No - not cost reflective and likely discriminatory
ii. Proportion of TEC	Generators are of different capacities (TEC), and their share of the cost of the interlink is based on the TEC of each generator.	Yes	No	No	No	Yes	No	No - not reflective of interlink size
iii. Shared and Unshared (equal)	Generators are of different capacities (TEC), and therefore may not ever be able to fully use an interlink, so should only pay for part of it they can use. Interlink capacity is divided into that which is shared by both generators, and that which only one generator can use. The cost of the shared capacity is divided *equally*. The cost of the capacity which can only be used by one generator is paid for by that generator.	Yes	Yes	No	No	Yes	No	Yes – but aware it does not reflect capacity to shore
iv. Shared and Unshared (proportion of TEC)	As (iii) except that the cost of the shared capacity is divided based on the TEC of the generators rather than equally to be most reflective of generator size.	Yes	Yes	No	No	Yes	No	**Preferred Solution (pre-Consultation)** Workgroup members liked the simplicity of the option, but are concerned that it does not reflect different load factors or capacity to shore.
v. Additional Firm Access	The costs of the interlink are apportioned based on how much additional firm capacity is provided to shore via the interlink.	Yes	Yes	Yes (firm access only)	No	Yes	No	No - Not relevant for this situation as not dealing with additional firm capacity to shore.

Apportionment Option	Description	Areas of concern for the Workgroup						Workgroup's view to proceed
		Reflect generator size	Reflect interlink size	Reflect capacity to shore	Reflect different generator load factors	Fully defined	Unaffected by changes to TEC	
vi. Non-firm access using ALF	The costs of the interlink are apportioned based on how much non-firm firm capacity is provided to shore via the interlink. Non-firm capacity is considered as offshore projects often have an output lower than their TEC.	Yes	Yes	Yes (non-firm access only)	Yes	Yes	No	Yes – as part of vii
vii. Combination of Firm and Non-Firm	The costs of the interlink are apportioned based on a measure of both firm and non-firm capacity, reflecting the capacity available to shore. This option apportions costs of the interlink based on a weighted sum of options (v) and (vi). The weighting is to be determined.	Yes	Yes	Yes	Yes	No (relies on arbitrary weighting)	No	Yes – but concerned about the arbitrary weighting. Workgroup members wished to seek further views from the industry Consultation on a potential weighting
viii. Restricted Availability Measure (using ALF)	Does not consider access to be firm or non-firm, but rather looks at a measure of 'restricted availability' which is potential capacity available on the other main circuit, by considering circuit capacities, TEC and ALFs.	Yes	Yes	Yes	Yes	Yes	No	**Preferred Solution (pre-Consultation)** Workgroup members wished to seek further views from the industry Consultation

Table 3: *Summary of the eight options for apportioning interlink costs between generators published in the Workgroup Consultation.*

3.50 Following the Workgroup Consultation, the Workgroup considered that development of **Option (viii) Restricted Availability Measure (using ALF)** was appropriate. The other option preferred by the Workgroup prior to the Workgroup Consultation, option (iv), was agreed not to be carried forward as it did not reflect the differing opportunities that generators would have to use the interlink based on other factors such as their estimated average output.

3.51 An extension of Option (viii) shares the costs of the interlink between the generators based on how much additional transmission capacity (MW) a generator has to shore using the interlink, using the following parameters:

- A measure of the likely output of the generator (the generator's TEC multiplied by its Annual Load Factor)
- A measure of the likely capacity available on the other main offshore transmission circuit(s) - the capacity of each of the other main circuit(s) to shore less the other generator's TEC multiplied by its Annual Load Factor; The capacity of, where appropriate, each interlink (in case this is a limiting factor).

3.52 These proportions are therefore reflective of the opportunity that a generator gains, on average over a year, by the existence of an interlink, but does not have to define that 'extra' transmission capacity (should their main circuit fail/fault) as either firm or non-firm. As TNUoS charges are an *ex ante* yearly product based on each generator's transmission capacity (TEC), the Workgroup concluded that such an approach was consistent with the CUSC charging methodology.

3.53 The Workgroup also decided to consider the "start of life", when one generator may commission before another, the effect of TEC changes during a generator's life, and the end of life when one generator may decommission before another and the impact on the proportions. These topics are considered on Page 30.

3.54 The Workgroup concluded that further investigation was needed on some of the other parameters which are not included in this model such as load profile, seasonal factors, volatility, output range and the likelihood of faults on offshore transmission circuits.

Exploration of alternative parameters

3.55 The Workgroup identified a series of other parameters which could be used in apportioning the interlink costs. These included load, load profile, volatility, correlation, and seasonal factors. The initial formula used only the generator Annual Load Factor (ALF) as a proxy for other parameters, and the Workgroup considered whether that was sufficiently robust.

3.56 In order to assess these parameters, metered output data for thirteen existing offshore windfarms for 2013/14 was analysed. At present there are no offshore transmission connected technologies besides wind. These thirteen windfarms were all commissioned prior to 2013/14 and operated throughout that charging year. Stations commissioned during 2013/14 were not included in the analysis due to the volatility in output experienced during the commissioning phase.

3.57 The thirteen wind farms under consideration were grouped into four geographic regions for comparison as shown in Table 4. The windfarms were grouped into these four regions to compare stations typical of those that are likely to be interlinked. The grouping reflects that interlinked stations are assumed to be geographically close.

| Offshore Windfarms grouped by geographic region			
East Coast	**Irish Sea**	**Solway Firth**	**Thames**
Lincs Wind Farm Sheringham Shoal	Barrow Offshore Ormonde Walney I Walney II	Robin Rigg East Robin Rigg West	Greater Gabbard Gunfleet Sands I Gunfleet Sands II London Array Thanet

Table 4: *The thirteen commissioned offshore windfarms whose 2013/14 metered output was analysed.*

The analysis considered the average output of each windfarm compared to its TEC (MW) level. This measure gives a **Load Factor**, and is so used to allow windfarms of different capacity to be compared more easily. A generator outputting at the maximum of their contracted TEC (MW) level for a period, would have a load factor of 1. A 100 MW windfarm with output of 25 MWh in a half-hour settlement period, would have a load factor of 0.5; a 200 MW windfarm with a constant of 75 MWh in a half-hour settlement period, would have a load factor of 0.75.

3.58 In analysing this data it is also worth noting that the output of a generator is net of the effect of faults and maintenance outages. As maintenance outages typically take place during the summer, these would, all other things being equal, result in the load factor being lower on average during these periods.

Distribution of Output

3.59 To consider how the output of offshore windfarms varies over the year, the cumulative distribution of load factor for all settlement period for all thirteen windfarms is plotted in Figure 6. The blue curve illustrates the cumulative load factor for all settlement periods in a year, the red curve for winter months (January and February), and the green curve for summer month (July and August).
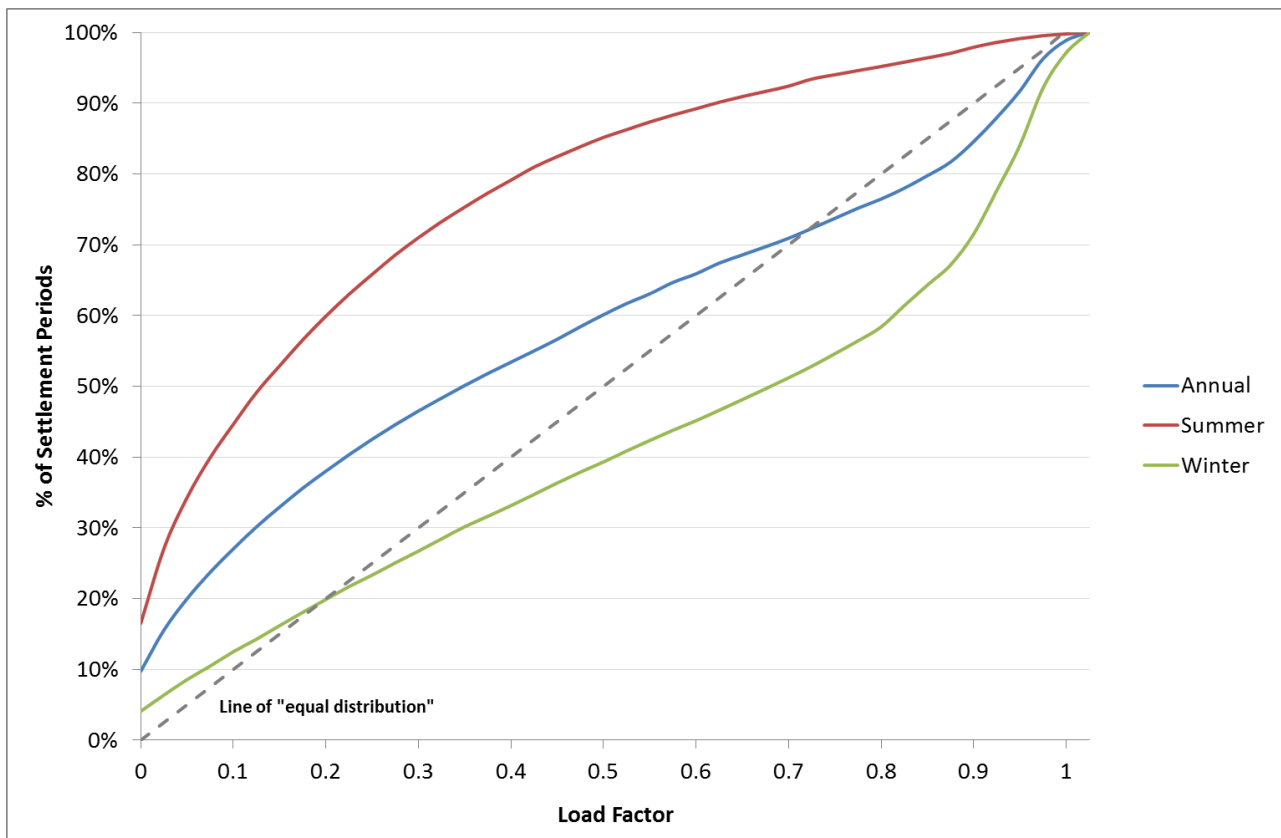
Figure 6: *Cumulative Load Factor profile curves for all stations for annual, and summer and winter two-month periods.*

3.60 From Figure 6, it can be seen that for a load factor of less than 0.5, occurs in 38% of settlement periods in Winter, 84% in summer and overall 58% of settlement periods across the year.

3.61 There is clearly a marked difference between the profile of output in winter and summer, as one may expect based on the prevailing weather conditions. However, as TNUoS charges are a yearly product, it is worth considering the annual profile in more detail. The grey dashed line represents an equal distribution of load factors across a year. In comparison, the blue annual lines tend to favour lower outputs so for most settlement periods you would expect the output to be low and as already explored, you would expect a windfarm to be outputting below 0.5 load factor for 58% of settlement periods, and above 80% for 24% of the time, so overall the load is quite evenly spread when considering on an annual basis.

3.62 As TNUoS charges are a yearly product, there is not likely to be a need to reflect these differences in the charges unless they are experienced differently by each generator. Therefore, we shall explore the correlation of output between generators.

Correlation

3.63 Recall that interlinked windfarms will be geographically close to each other as they must share a common onshore substation. Therefore, the correlation of the output of each station within a geographic region was considered. If station outputs move upwards and downwards in sync, then the stations will be well correlated. If there is not synchronisation between the stations' output there is said to be no correlation in their outputs.

3.64 The reason for studying correlation is to ensure that similarly located windfarms have similar outputs and there are not significant other factors that should be taken into account.

3.65 The data in Figure 7 illustrates that the output from geographically close offshore windfarms is very similar (shown by the correlation factors near 1). This suggests that there are no significant factors which cause one offshore generator to output differently to another. As we do not know *a priori* when a generator would use an interlink, and transmission network charges are an annual product, it seems appropriate to treat all offshore generators the same.
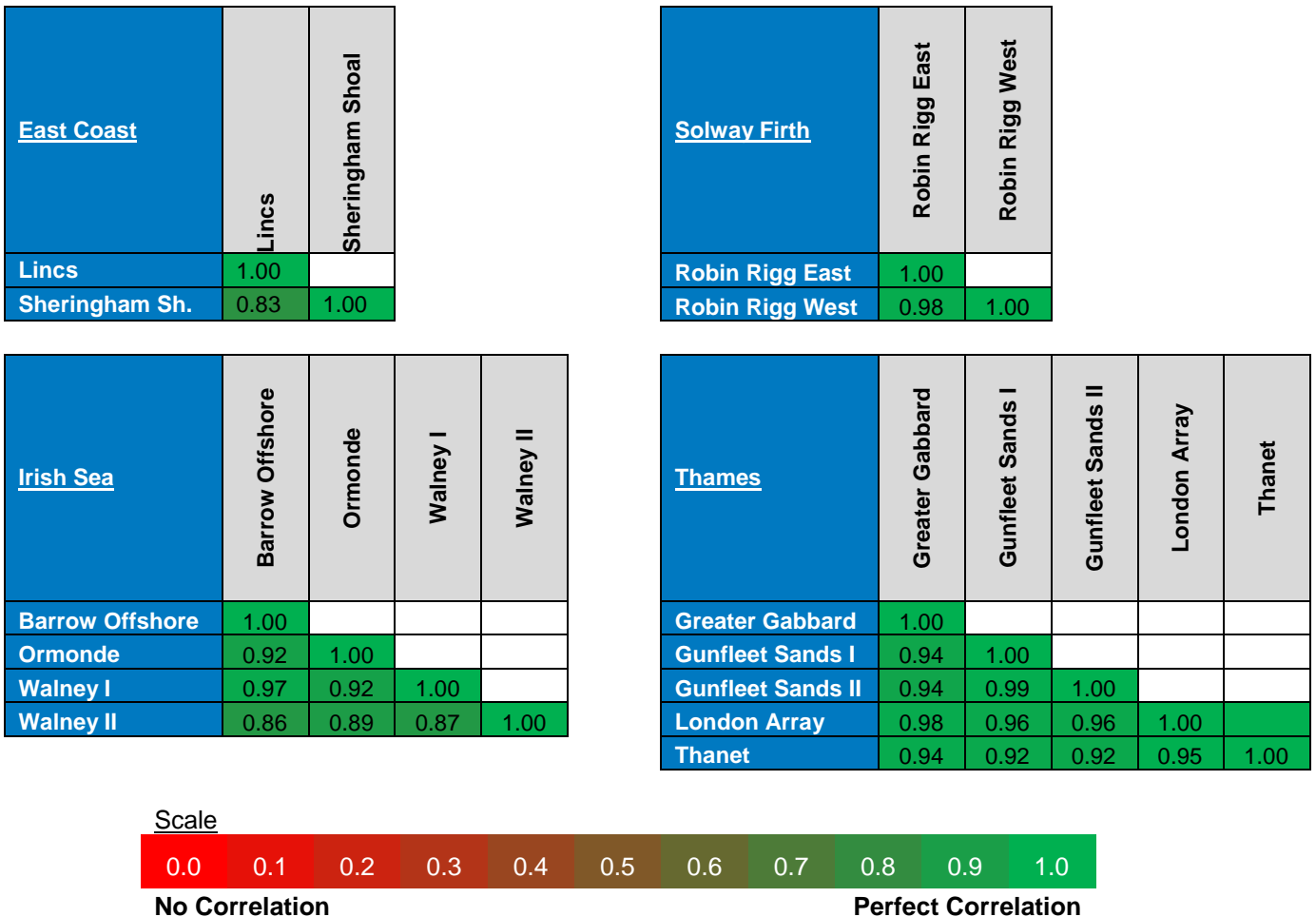
East Coast

	Lincs	Sheringham Shoal
Lincs	1.00	
Sheringham Sh.	0.83	1.00

Solway Firth

	Robin Rigg East	Robin Rigg West
Robin Rigg East	1.00	
Robin Rigg West	0.98	1.00

Irish Sea

	Barrow Offshore	Ormonde	Walney I	Walney II
Barrow Offshore	1.00			
Ormonde	0.92	1.00		
Walney I	0.97	0.92	1.00	
Walney II	0.86	0.89	0.87	1.00

Thames

	Greater Gabbard	Gunfleet Sands I	Gunfleet Sands II	London Array	Thanet
Greater Gabbard	1.00				
Gunfleet Sands I	0.94	1.00			
Gunfleet Sands II	0.94	0.99	1.00		
London Array	0.98	0.96	0.96	1.00	
Thanet	0.94	0.92	0.92	0.95	1.00

Scale

0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0

No Correlation   **Perfect Correlation**

Figure 7: *The correlation of output of offshore windfarms by geographic region during 2013/14.*

Volatility of Output

3.66 Figure 8 illustrates the maximum, minimum, and average daily load factors experienced across the thirteen windfarms, per month, in 2013/14. The annual figures, for comparison, are a Load Factor of 0.45 and a Standard Deviation of 0.29.

3.67 For almost the entire charging year, there exists a station which for one day a windfarm has zero output (load factor = 0) and nearly full output (load factor ≈ 1). Although the average varies throughout the year (highest in winter, lowest in summer), the standard deviation is relatively constant meaning we expect a volatile spread of outputs throughout the charging year across all the windfarms located offshore around GB.
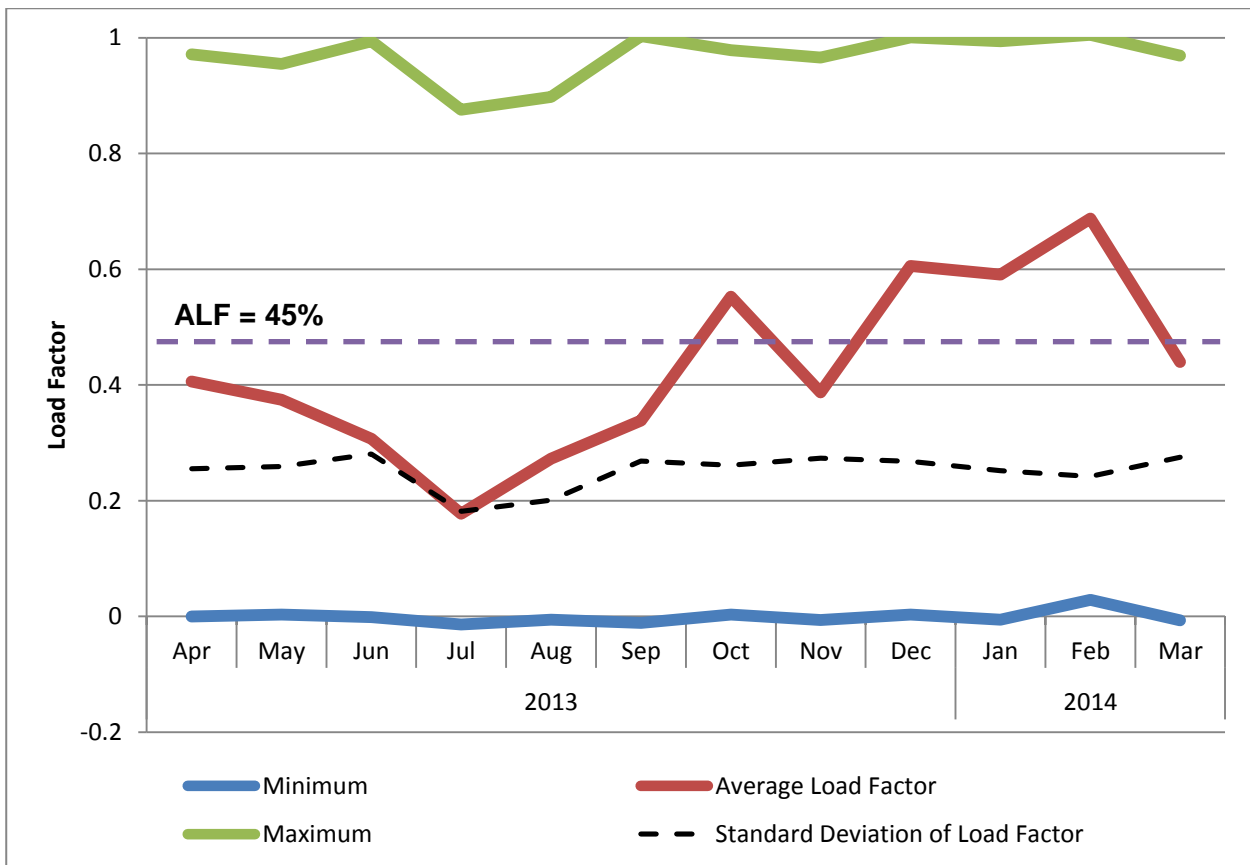
Figure 8: *The minimum, maximum, and average daily load factors for all commissioned offshore windfarms per month, and the standard deviation.*

Likelihood of a fault on an offshore transmission circuit

3.68 It was explored by the Workgroup whether there should be a factor included in the formula to account for the likelihood of there being a fault on a main radial circuit. The reason for doing so being that if one generator's radial circuit is more likely to fail compared to another, then that generator would have more benefit from the interlink, and so, in principle, should pay proportionately more.

3.69 There is no codified methodology for determining *a priori* the likelihood of one transmission circuit faulting compared to another. In order to explore if such a methodology could be created the Workgroup considered the *ex post* data from the National Electricity Transmission System Performance Report 2013-2014[6] on transmission system availability.

3.70 The Overall System Availability for Offshore Transmission was 99.43% in 2013/14. The availability of individual offshore transmission circuits is show in Table 5.

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6   http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Report-explorer/Performance-Reports/

Offshore Transmission Networks % Annual Availability		
	2012/13	**2013/14**
TC Robin Rigg	99.89	99.85
TC Gunfleet Sands	100	100
TC Barrow	100	99.64
TC Ormonde	100	100
BT Walney 1	97.47	99.99
BT Walney 2	100	94.89
BT Sheringham Shoal	N/A	99.20
BT London Array	N/A	99.97
BB Greater Gabbard	N/A	99.81

Table 5: *Annual Availability for Offshore Transmission Networks, taken from National Electricity Transmission System Performance Report 2013-2014*

3.71 Of the outages experienced on offshore transmission networks, most are caused by either planned outages (for example for maintenance), or as a result of non-OFTO activities. These non-OFTO activities may be due to a fault on the DNO network (if an offshore circuit connects via a DNO network), or the generator needing to take an outage for maintenance or development.

3.72 The one outlier from Table 5 is the Walney 2 offshore transmission circuit. In 2012/13 it had 100% availability, but this dropped to the lowest availability of 94.89% in 2013/14. During 2013/14 the data shows that the Walney 2 circuit had 100% availability for 11 months but dropped to 41.34% in November 2013. This was due to an 'OFTO unplanned' outage on 6 November, which lasted for 17.7 days. As the Walney 2 circuit is a single circuit, the fault on the 132kV land cable caused this outage. This is precisely the situation when an interlink may have helped to allow the affected windfarm to output some energy via an alternative route.

3.73 Overall, the Workgroup noted that fault probabilities on the offshore transmission networks are low. To predict in advance whether one offshore transmission circuit or another will fail would be based on a stochastic model which would be based on various parameters and subjective modelling assumptions.

3.74 To reconcile any interlink costs in the charging methodology after the event, i.e. based on actual outages, would be a significant change from an ex ante TNUoS methodology to an ex post methodology. This was deemed beyond the scope of the Workgroup.

3.75 Based on these findings it seems appropriate to not include any measure of offshore transmission circuit fault likelihood in the formula, as they cannot be determined in advance with any confidence.

Moving toward a measure of output

3.76 One observation about offshore transmission circuit faults, which is the situations in which an interlink would be needed, is they tend to be of longer duration than onshore transmission circuit faults. This is because of the difficulty of accessing and fixing offshore circuits when a fault occurs; especially over the autumn / winter period. One Workgroup member noted that obtaining a suitable vessel to access, and then locate and repair the fault may take several weeks particular during the peak (summer) offshore maintenance season.

3.77 The Workgroup noted that there is significant volatility in the output of windfarms in between days. As it is not known in advance when a fault will occur or how long that fault will occur, there is need to approximate the benefit a generator may gain from the interlink. The Workgroup therefore considered the rolling average load factor as a way to study the likely output over time.

3.78 The charts in Figure 9 are various rolling average load factors for various time periods. For clarity, only the five windfarms in the Thames region are illustrated, although data from the other three geographic regions studied are similar.

Legend: GREATER GABBARD OFFSHORE WIND FARM — GUNFLEET SANDS I — GUNFLEET SANDS II — LONDON ARRAY — THANET OFFSHORE WIND FARM
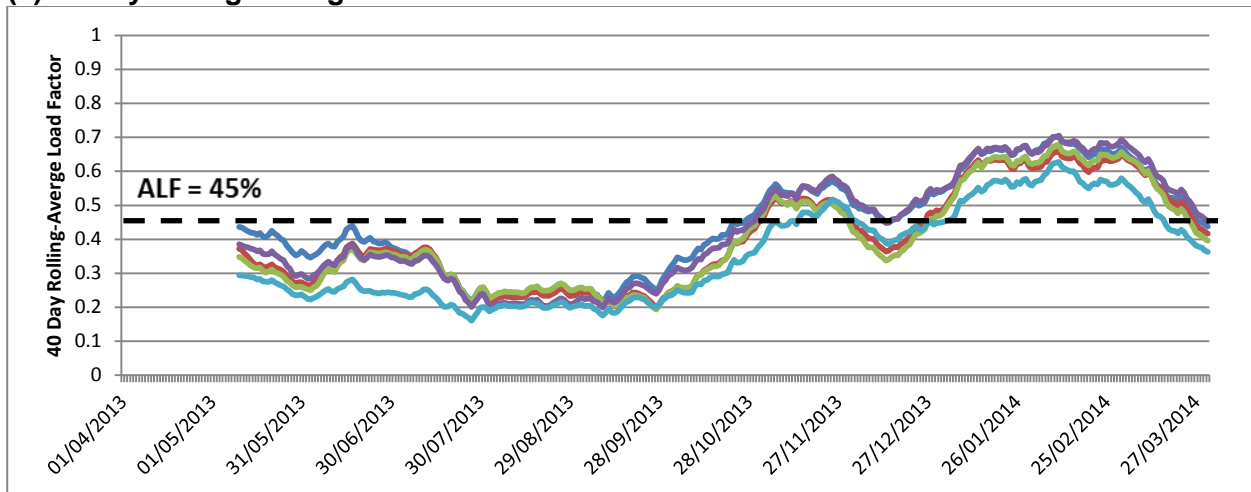
(a) Daily Load Factor
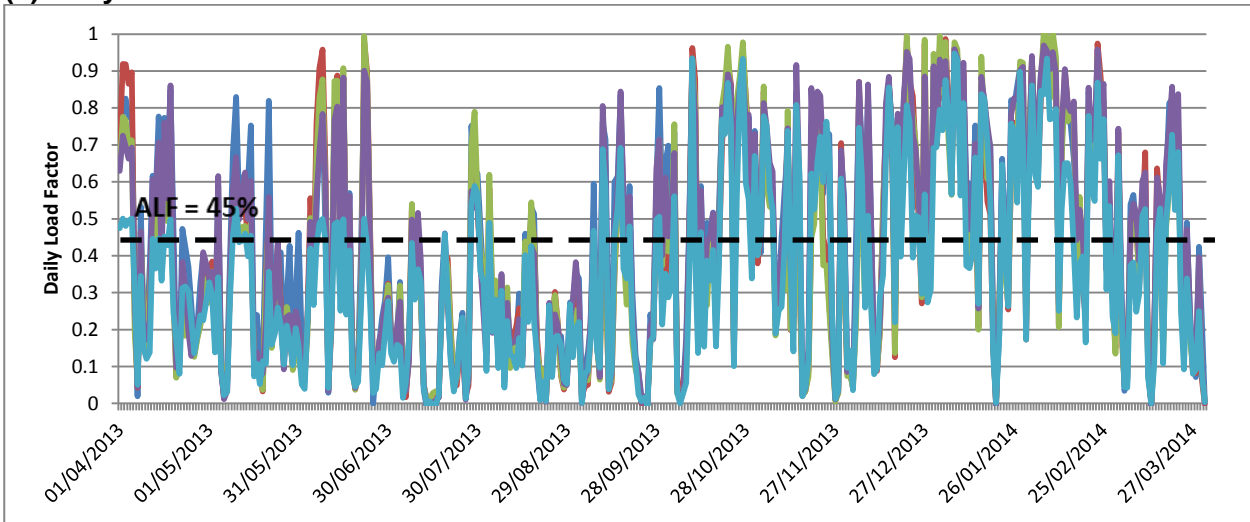
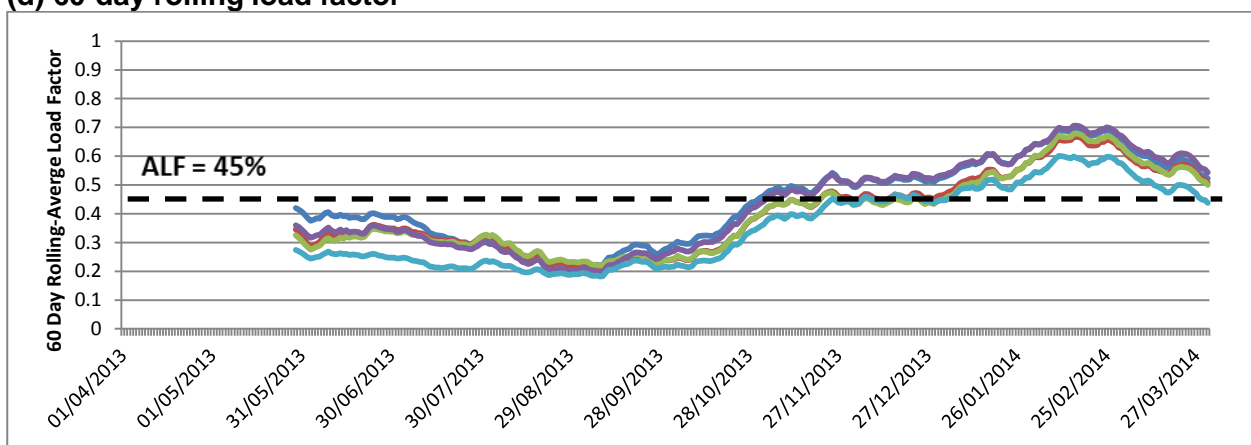**(b) 20-day rolling average Load Factor**
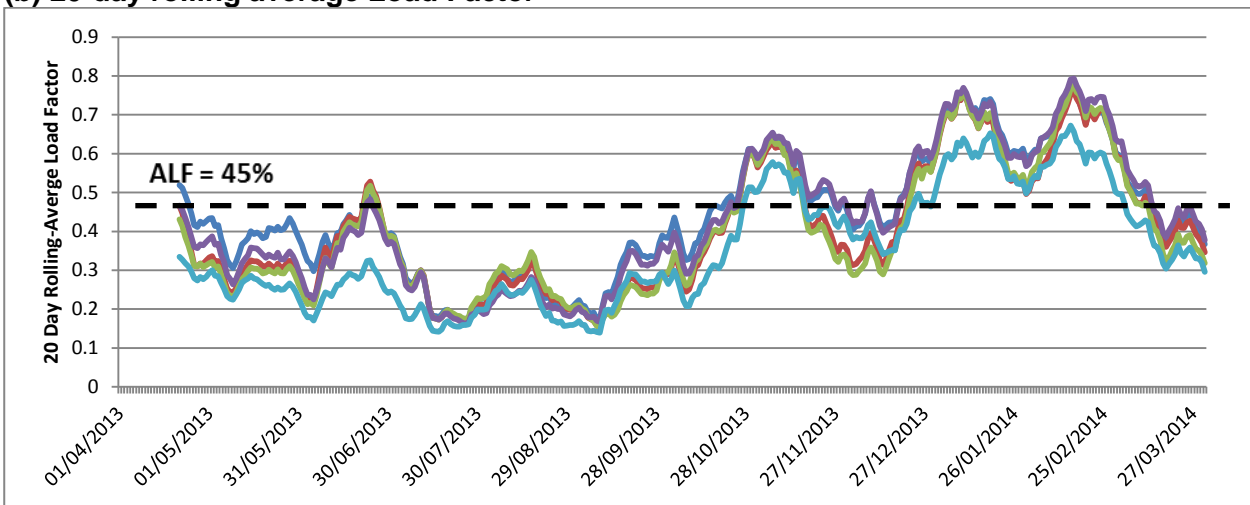
(c) 40-day rolling average Load Factor

(d) 60-day rolling load factor

Figure 9: *Various average Load Factors for five windfarms in the Thames region. (a) daily average, and then rolling averages for (b) 20-days, (c) 40-days and (d) 60-days.*

3.79 The observation from this data is that the longer time period that the average is taken, the closer the value comes to the Annual Load Factor. Clearly, there is a seasonal feature to the output, however, this is experienced equally by each offshore generator, and as TNUoS charges are an annual product it seems appropriate to use the ALF as a proxy for annual output.

The Annual Load Factor

3.80 The Annual Load Factor is a concept introduced under CMP213 (Project TransmiT) for use in setting elements of the TNUoS charges for all generators. As an established concept from a previous CUSC modification, the Authority has already opined on the ALF methodology as being appropriate as a measure of the average output of a particular generator and thus for setting and levying charges for that generator.

3.81 The calculation of the ALF has two important key features which are relevant to this discussion:

(a) For a new power station, a generic ALF is used based on the ten most recently commissioned power stations of the same fuel type / technology; and

(b) The specific ALF for each power station is a five year rolling average, disregarding the highest and lowest yearly values. This removes the effect of outlying years and leaves three actual years upon which that power station's ALF, for the next charging year, is based.

3.82 For the purposes of setting the apportionment of any interlink costs, it was agreed that we should use a measure based on the generator ALF, however, for clarity it would be termed the **"ILF" (Interlink Load Factor)** to avoid confusion. For the formula, the ILF for each offshore station would be the generic ALF for the fuel type, until all generators benefiting from an interlink have their own specific ALF based on five years of data. Once all generators have a specific ALF, this would be fixed going forward.

3.83 This approach seeks to provide clarity and transparency to the generator. Other alternatives were explored (fix the ILF for a price control, update annually (based on the changing individual ALFs) or, another period of time), but these were deemed to be less suitable to that outlined above as they did not provide stability.

The situation of a radial connections with multiple transmission circuits

3.84 The Workgroup explored the situation of when one or more generator has chosen to have a double or multiple transmission circuits as their radial connection, which is above the standard single radial circuit. In this case, the charging methodology means the generator will pay for all of the revenue costs associated with the radial circuits.

3.85 It was noted that the generator with a double or multiple circuits is unlikely to want to use an interlink due to the high costs and existing redundancy of their main transmission link. It was also noted by one Workgroup member that the premise of this CMP242 modification was as an alternative to the single offshore generator with a double circuit transmission link. However, it was agreed that a single circuit generator may wish to interlink to a double circuit generator, so the Workgroup considered the situation warranted further discussion.

3.86 The Workgroup noted that it is highly unlikely that offshore transmission networks would be developed with significant redundancy due to the cost of the cables, and the standard offshore design detailed in the SQSS is for a single cable to shore.

3.87 The current 'most redundant' offshore transmission circuit is Thanet, which has 2 x 183 MW circuits, for a generator with TEC of 300 MW. This means that in the event of a single circuit failure, the generator would still be able to output up to 183 MW of its output. Other windfarms (e.g. Gwynt y Mor and London Array) have multiple transmission circuits to shore that, in total, are only just larger than the overall generator's capacity.

3.88 The Workgroup also considered what is a 'credible fault' when considering an interlink. Onshore a generator is provided with a transmission circuit which permits them to export their full (MW) capacity in the event of a single circuit fault (SQSS 2.6.1). Importantly, this means that a double circuit fault would mean that an onshore generator would have no export capacity to the transmission system.

3.89 Therefore, in the case of an offshore generator it is appropriate to only consider a single circuit fault. Therefore, in this situation, the offshore generators with multiple circuits will still have some capacity to shore in the event of a single circuit fault, and this *remaining capacity* should be reflected in the formula for apportionment.

Formula for apportionment

3.90 The formula developed by the Workgroup, based on, and extended from, Option (viii) from the Workgroup Consultation is as follows:

(a) Each offshore generator will pay a proportion of the interlink(s) costs based on their ability to get energy to shore in the event of a single circuit fault, compared to the same measure for other offshore generators connected via the interlink(s).
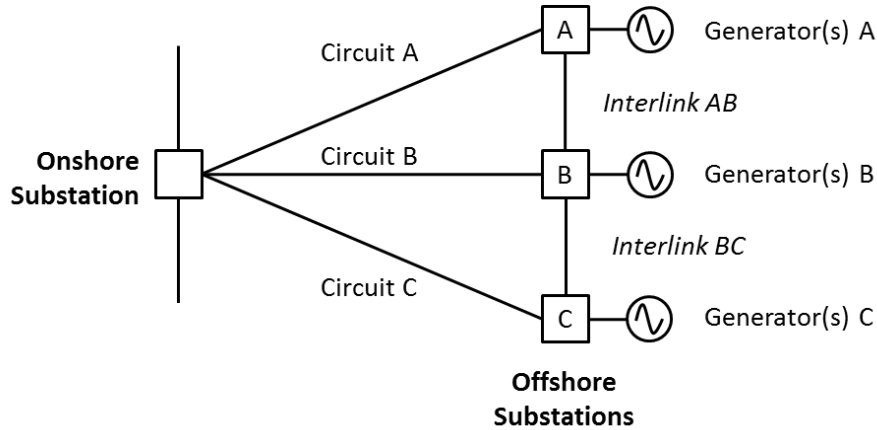
Figure 10: *Configuration with three offshore substations and two interlinks.*

(b) From substation A, there are two routes to shore in the event of a fault on circuit A – via Interlink AB and Circuit B, and via Interlinks AB, Interlink BC and Circuit C. This transmission capacity to shore would be limited based on the likely output of the generator less any remaining capacity on A's main circuit in the event of a single circuit fault.

(c) Analogous descriptions apply for both substation B and substation C.

(d) In principle the formula can be extended beyond two interlinks, however, the algebra becomes difficult to present in a closed form.

3.91 The formulae are as follows. If any given formula results in a negative number, it is taken to be zero for the purposes of the proportions to avoid any party receiving money to use the interlink.

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

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

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

Cap_{IAB} = total capacity of the Offshore interlink between substations A and B
Cap_{IBC} = total capacity of the Offshore interlink between substations B and C
Cap_X = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault.

$$TEC_X \quad = \quad \text{the sum of the TEC for the generators connected to offshore substation X,}$$

where X is A, B or C, where the value of TEC will be the maximum TEC that each generator has held since the initial charging date.

ILF_X = Offshore interlink Load Factor, where X is A, B or C.

Commissioning, decommissioning and TEC Changes

3.92 The Workgroup considered the three stages in the operational cycle of an offshore generator and what impact these might have on the proportioning of the interlink costs paid by each generator:

(a) at commissioning;

(b) changes to TEC during operational life;

(c) at decommissioning;

3.93 This topic also raised the issue of whether, at some points, elements of the interlink cost should be socialised through the generation residual element of the TNUoS charge. Overall it was felt that the interlink was for the benefit of those connecting generator parties and so they should pay, but that this does warrant further discussion to avoid one party paying being directly affected by the decisions of another generator.

At Commissioning

3.94 At Commissioning of an interlink, it is possible that an OFTO revenue stream for the interlink will be generated prior to all generators being connected and paying TNUoS. Therefore the situation was considered of how the costs should be apportioned before all generators have connected.

3.95 The Workgroup considered passing the entire cost of the interlink on to the first generator that connected, and then refining the proportions as further generators connect to share the charge. However, this was felt to be both unjustified and non-cost reflective on the first generator, as the interlink had been planned, designed and costed for more than one party.

3.96 In this case, the Workgroup decided it would be appropriate to calculate the proportions based as if all the generators for which the interlink was designed were connected, using their future contracted value(s) of TEC. The proportion of the charge then associated with the generator(s) not yet connected would then be recovered from the residual until each generator connected. It was noted that this may only be a few months apart, but it may fall into two different charging years so could have a significant impact on all generators' charges.

3.97 The recovery of an element of the charge through the residual was deemed appropriate, as it is consistent with the onshore methodology and avoids a step-change and potentially onerous charges for the first generator due to their commissioning date being ahead of another windfarm.

TEC Changes during operational life

3.98 The consequences of one offshore generating party using an interlink, and then changing their TEC was also considered by the Workgroup, as this would potentially affect the costs to the other generator who uses that interlink. The Workgroup considered three potential options:

- do nothing – a generator's charges can be affected by another generator's change in TEC;
- the proportions of the interlink costs for each generator are fixed upfront, for say a TO price control[7], so they are not affected (in terms of paying more of the cost of the interlink) by the other generators' TEC changes (but they are by their own changes in TEC);
- a hybrid cap/collar approach is implemented – whereby each generator is capped to changes caused by the other generator, and collared against a reduction due to their own changes.

3.99 In the case of offshore generation, it does not seem appropriate to 'do nothing'. Costs associated with offshore transmission circuits can be significantly higher than circuits of similar length / capacity onshore, and could render one offshore generator economically unviable if their proportion of the cost of the interlink increased by the decision of the other offshore generator. This situation does not occur onshore and is particular to the offshore transmission regime.

3.100 Fixing the proportion of the interlink cost sharing upfront provides stability to each offshore generator, and gives them the certainty that they cannot be affected by the other generator reducing their TEC. The consequence is that the risk associated with a change reduction of one of the generator's level (MW) of TEC is carried by the overall generator residual element of TNUoS, as any under-recovery from that generator's TEC reduction will be made up through the residual tariff, socialising the cost of the spare capacity across all generators (onshore and offshore). This approach is consistent with the current onshore and offshore approach in the methodologies.

3.101 The hybrid cap/collar is potentially difficult to implement, complex and not consistent with the rest of the CUSC charging methodology.

3.102 Following the Workgroup Consultation, and further discussion on the impact of the 'step change' in charges at the Transmission Price Control, it was agreed by the Workgroup that it was preferable to avoid a potential step in charges associated with the interlink at the price control, but still avoid one generator being affected by the other's downward TEC change.

3.103 It was agreed by the Workgroup to use the *maximum* (MW) value of TEC that an offshore power station had held since they became liable for charges. This situation ensures that one generator is not affected by another generator's decision to decrease their TEC. This risk of gaming, in the context of the OFTO regime, was considered small.

At Decommissioning

3.104 This situation is analogous to the 'At Commissioning scenario', except now one generator may decommission and stop paying the charges associated with the interlink before the other generator.

3.105 The Workgroup agreed to continue to use the maximum (MW) value of TEC that the offshore generator had held, and so it continues to have a proportion of the interlink revenue cost associated with it, thus avoiding the other generator's interlink charges increasing unexpectedly. This has the consequence that part of the revenue associated with the interlink would need to be socialised through the generator residual.

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[7] The next GB TO price control is expected to be eight years from 2021/2022.

Priority access for generators on their "own" transmission circuit

3.106 The Authority Representative raised the query of whether giving priority access for a generator directly connected to their main radial transmission circuit, with the other generator having access only to any residual spare capacity via the interlink was in breach of the principle of non-discriminatory access to Transmission circuits.

3.107 In terms of constructing/owning such an offshore transmission network including an interlink, it was noted that the transmission owner (OFTO in this case) is not showing any preference to either generator – but rather providing an opportunity for access subject to system operability constraints.

3.108 In the event of a fault on a main circuit, which caused the interlink to be used, the offshore generator whose main transmission circuit is still operational could continue to use their circuit up to their contracted (MW) TEC level, with any residual spare capacity on that operational circuit (up to the circuit's rating) being available to the other generator via the interlink. Overall, having an interlink provides more opportunity and flexibility to the generator and the NETSO than would otherwise be available, as without an interlink a fault may take a generator off the transmission system completely.

3.109 The Bilateral Connection Agreement between the NETSO and each offshore generator will specify the situation for the use of the interlink, so this will be known in advance by all concerned. Moreover, each offshore generator is paying for their firm capacity on their main circuit via their TNUoS charge. The other generators are paying to use any spare capacity owing to the interlink, and this is reflected in the interlink charge.

3.110 The day-to-day secure use of the transmission network is a System Operator issue, who has the licence requirement to maintain the transmission system within the limits specified in the SQSS, and in order to do so, there may be occasions when it is not possible to operate the system as defined in the BCA, however, the NETSO would use their usual suite of balancing tools including Bid-Offer-Acceptance to achieve this.

3.111 The Workgroup concluded that their assumption was valid, and that any changes to transmission access rules or licensing arrangements would be beyond the scope of this charging modification.

Other impacts on the OFTO regime

3.112 For the offshore regime, the Authority sets the final transfer value at which generator developers sell their transmission assets to a new offshore transmission licensee (OFTO) prior to asset transfer. The value is based on the actual costs incurred and reflects an assessment of the economic and efficient capital costs incurred in the development, construction, and installation (including civil works) of the relevant offshore transmission assets. This value is reflected in the tender revenue stream, or TRS as currently defined in standard licence condition E12–J2[8] a fixed value (subject to certain income adjusting events and mechanisms) that rises annually with inflation. The value determined through the cost assessment process will only include capital expenditure incurred in an efficient and economical manner. Therefore it may not include all costs incurred by the generator developer.

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[8] Based on the Generic OFTO licence for Tender Round 3, Version 3 published by Ofgem.
https://www.ofgem.gov.uk/publications-and-updates/generic-offshore-transmission-owner-ofto-licence-tender-round-3-version-3

3.113 One Workgroup member noted that any capacity on the transmission assets built by the developer/generator which was not permitted by the Authority as part of the cost assessment / asset transfer process, may at some future point be used (and become part of the allowed OFTO revenue) as a result of the interlink being built. The Workgroup member noted that this situation gives rise to additional 'windfall gains' revenue to the OFTO (as they have not paid for the asset, but now receive revenue for that 'free' asset), a potential change in the existing generator's charge, but no further revenue to the developer/generator as the cost of the asset built would not have been recognised in the Authority's initial asset transfer; thus leading to 'windfall losses' for the developer/generator (who not only receive no recompense for the asset transferred but may also be subject, in certain circumstances, to paying the associated OFTO charges for those assets). Ofgem noted that this scenario is unlikely to happen as the additional transmission capacity built (and transferred) by the developer/generator (to the OFTO) is either likely to have been provided for in the asset valuation / transfer as it is anticipatory investment (and so is covered by the GFAI process), or it is because of using a standard cable rather than a bespoke size. Any particular case would be considered as part of the development of a scheme involving an interlink, and needs to be agreed by the Authority as part of their cost assessment / asset transfer process for developer/generator 'own build' projects.

3.114 The Workgroup agreed that there may be a requirement to raise a request to make changes to the licence to deal with this situation. It was confirmed that this scenario is not unique to interlinks. The Workgroup noted this point, and although it is beyond the scope of the modification, note it may need to be addressed by the Authority.

4   Original Proposal

4.1   The CMP242 proposal aims to ensure that there are appropriate charging arrangements set out in the CUSC for offshore transmission networks that links two (or more) offshore substations (used by offshore generators) which are connected to the same onshore substation; i.e. are interlinked offshore.

4.2   As originally proposed in the modification proposal, the proposal stated:

It is proposed that the TNUoS charging methodology within Section 14 of the CUSC is modified to ensure that both interlinking circuits and additional capacity that can be utilised on the export cables to shore are appropriately charged, such that:

(a)   The charge for capacity on an interlinking circuit that can be utilised by generation on either end of the link is set such that each party pays an amount representing an equal proportion of the associated OFTO revenue;

(b)   The charge for any capacity on an interlinking circuit that can only be utilised by a generation on one end of the link is set such that the relating generation pays a charge equivalent to the associated OFTO revenue;

(c)   The Local circuit charge for an offshore generator will reflect any additional capacity on export cables to shore that is made available through use of an interlinking circuit.

4.3   During the Workgroup phase, the Original Proposal was refined and clarified by the Proposer such that the final presented position was:

The TNUoS Charging Methodology (Section 14 of the CUSC) be modified so that:

(a)   The definition of an offshore interlink is included

(b)   The total OFTO revenue associated with the interlink(s) will be apportioned between those generators who benefit from it.

(c)   The methodology will apply when the interlink(s) was included in the design prior to any connected generator being financially committed, or if one or more generator is financially committed, these generators agree to the interlink(s).

(d)   The proportion paid by each offshore generator will be based on a measure of likely available capacity to shore in the event of one offshore circuit failure for a generator compared to the other generator(s). The principles used in the calculation are:

(i)   The Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF, see CMP213) as a measure of likely generator output. Until all generators affected by an interlink have a station specific ALF based on five years of data, the generic ALF for the fuel type will be used for all stations as the ILF. When all generators have a station specific ALF, the values of the ALF in the first such year will be used as the ILF in this calculation for all subsequent years.

(ii)   The (MW) value(s) of TEC used in this calculation will be the maximum TEC that each generator has held during its operational life or if a generator is yet to connect its future contracted value.

(e)   The Local Security Factor will need to be adjusted for offshore generators with interlinks so that the additional OFTO revenue associated with the interlink circuit is captured. (See below)

Local Security Factor

4.4 It is proposed to adjust the Local Security Factor to account for the additional revenue that an offshore generator is liable to pay through their charges for the interlink. The use of the Local Security Factor is designed to ensure consistency with the existing CUSC charging methodology, and to ensure integration of the charges within the Transport Model. However, the Local Secuirty Factor with an interlink will not reflect the additional redundancy in the traditional sense (i.e. multiple circuits), but rather the additional opportunity provided by the interlink.

4.5 It is proposed that the Local Security Factor for an offshore generator with an interlink is updated as follows:

$$LSF = \frac{IRev \times Rating}{CRev \times TEC} + LSF_i,$$

where LSF_i is the initial Local Security Factor calculated as if the interlink were not present.

4.6 The demonstration that this updated Local Security Factor results in an offshore generator with an interlink paying the correct amount in charges, can be found in Annex 7.

4.7 A spreadsheet illustrating the implementation of the Original Proposal is available on the National Grid website for CMP242: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP242/

5 Workgroup Alternatives

5.1 The Workgroup met once the Workgroup Consultation closed to discuss whether to take forward any further WACMs for CMP242. At the meeting on 4th September 2015, they agreed to take forward two WACMs.

WACM1: Formula with Optional Negotiation

5.2 WACM1 would be as the Original Proposal, however in addition, it would alternatively allow negotiation of the interlink cost proportions as follows:

(a) The relevant offshore generators negotiate a proportion (summing to 100%) of the interlink OFTO revenue associated with an interlink to be paid by each User.

(i) In the case three months prior to OTSDUW asset transfer (generator build) or the Charging Date (OFTO build) of the first User.

(ii) Each charging year, these parties may adjust their proportions by providing three months' notice before the charges are set for a given charging year to NGET.

(b) Once informed, NGET would apply the notified proportion until informed otherwise by the relevant Users.

(c) If the Users are unable to reach an agreement on the interlink cost allocation between them they can raise a dispute. Any dispute between two or more Users as to the proportion of the interlink costs that is proposed to be allocated to them shall be managed in accordance with CUSC Section 7, Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be read as to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to any appeal for judicial review of any determination, be final and binding on the parties.

WACM 2: Negotiation Only

5.3 WACM2 would still use the definition of an interlink and the adjustment of the Local Security Factor from the Original Proposal, but would require the proportion of the interlink OFTO revenue (costs) that is to be recovered from each generator to be determined by negotiation only (between the relevant generator parties).

5.4 The process that applies would be 5.2 (a) – (c) as in WACM1, with the exception that under (a) the parties *must* negotiate a proportion rather than *may*.

6   Impact and Assessment

Impact on the CUSC

6.1   Changes to Section 14, Part 2 - Section 1 - The Statement of the Transmission Use of System Charging Methodology.

Impact on Greenhouse Gas Emissions

6.2   None identified.

Impact on Core Industry Documents

6.3   None identified.

Impact on other Industry Documents

6.4   None identified.

7   Proposed Implementation and Transition

7.1   It is proposed to make the amendment to the CUSC charging methodology as soon as practically possible; namely ten Working Days after an Authority decision to approve the change; so that it could be used when an appropriate configuration of interlink(s) is brought forward.

7.2   As there are believed to be no existing parties affected by this change, it is proposed that there is no transitional period and no transitional arrangements need to be specified.

8 Workgroup Consultation Responses

8.1 Three responses were received to the Workgroup Consultation. These responses and the Workgroup Consultation alternative request are contained within Annex 4 of this report. The following table provides an overview of the responses received:

Respondent	Do you believe that the CMP242 Original Proposal or any of the potential options for change better facilitates the Applicable CUSC Objectives?	Do you support the proposed implementation approach?	Do you have any other comments?
Dong Energy	Yes, in our view CMP242 better facilitates all three of the applicable CUSC objectives for Charging. CMP242 facilitates competition in the generation of electricity be implementing a robust and appropriate method of allocating the cost of an offshore interlink. Without CMP242 offshore developers would have no certainty over the charges they would face for an interlink, and this would inhibit their development. By enabling offshore generators with interlinks the modification enables the development of more complex offshore networks, and through that future, more affordable offshore generators. The Workgroup's preferred charging methods will find ways of reasonably allocating the costs of the interlink to the generators that benefit. CMP242 accurately reflects that future OFTOs will be more likely to contain interlinks.	Yes, we do not see any issues with the implementation.	Yes. We would like the Workgroup to consider adjusting one of their key assumptions. The assumption is that "Priority for export will be given to the generator connected via the remaining main circuit, and the other generator may need to reduce their output if they wish to use the interlink to export via the remaining main circuit". interlinked offshore generators may have agreements between themselves over how their capacity is curtailed in the case of an outage. For example, two offshore generators might have an agreement to curtail themselves equally. The charging methodologies developed as part of CMP242 are based on the assumption that priority goes to the generator connected to the main circuit. However, in our view they are still valid even if interlinked offshore generators choose to curtail themselves differently, as this will be a technical and commercial agreement made outside of the CUSC. We believe that CMP242 needs to reflect this distinction.

Respondent	Do you believe that the CMP242 Original Proposal or any of the potential options for change better facilitates the Applicable CUSC Objectives?	Do you support the proposed implementation approach?	Do you have any other comments?
Scottish Power Renewables	(a) Yes, SPR believe that CMP242 deals with the charging of a section of network otherwise not adequately covered by the existing methodologies and therefore facilitates competition. (b) Yes, as in (a) above, CMP242 seeks to address a more cost reflective position to charging for interlinks (c) Yes, as the same accounts for the developments in offshore transmission network.	Yes, SPR support the proposed implementation approach.	Not at this time.
SSE	CMP242 Original, if it led to existing generation projects being denied the opportunity choose to pay for (and use) the interlink will not better facilitate the applicable Charging Objective (a) as regards effective competition in generation as it will (i) render those generators less economic and competitive retrospectively and (ii) increase regulatory risk that other retrospective changes could occur in the future which render existing generators uneconomic.	We note and support the proposed implementation approach set out paragraphs 3.5-3.6.	In respect of the generator own build / Authority transfer value situation (as noted in paragraph 2.24-2.25) we note that if a proportion of the assets are required (by the Authority) to be transferred (by the generator to the OFTO) at less than their actual cost and then the proportion of the assets are subsequently utilised as a result of the interlink then there will need to be either a refund to the generator of the value of the proportion of the assets transferred (where no value was initially transferred) or an ongoing payment /charge reduction for that generator to reflect the utilisation of that proportion of the assets initially not valued when transferred. To do otherwise could be in breach of EU law (such as Article 1 of the First Protocol of the European Convention on Human Rights).

9   Views

Workgroup View

9.1   The Workgroup believes that the Terms of Reference have been fulfilled and CMP242 has been fully considered. On 4th September 2015, the Workgroup voted unanimously that the Original and both WACMs 1 and 2 all better facilitate the Applicable CUSC objectives than the CUSC baseline. In terms of which option best facilitates the objectives, half of the Workgroup voted that the Original Proposal is best, whilst half of the Workgroup concluded that WACM1 best facilitates the Applicable CUSC (charging) Objectives and should be implemented. The votes are summarised in the tables below.

9.2   For Reference, the Applicable CUSC (charging) Objectives are:

(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.

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

Workgroup Vote

9.3   The Workgroup met on 4th September 2015 and voted on the Original proposal and the two Workgroup Alternative CUSC Modifications, the votes received were as follows.

9.4   Garth Graham voted on behalf of Simon Lord and Joe Dunn. The results of the final vote, Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives have been validated by Joe Dunn.

Vote 1: Whether each proposal better facilitates the Applicable Objectives

Original Proposal: Formula Only.

Workgroup member	Objective (a)	Objective (b)	Objective (c)	Objective (d)	Overall
Paul Wakeley	Yes – a transparent methodology, consistent with the framework	Yes	Yes	Neutral	Yes
Garth Graham	Yes – a transparent methodology, consistent with the framework	Neutral - Focus is on development on Transmission business. Cost reflective as a consequence	Yes	Neutral	Yes
Simon Lord (Garth Graham)	Yes	Yes	Yes	Neutral	Yes
Aled Moses	Yes provides best guidance to NG & businesses	Yes	Yes	Neutral	Yes
Lewis Elder	Yes	Yes	Yes	Neutral	Yes
Joe Dunn (Garth Graham)	Yes	Yes	Yes	Neutral	Yes

WACM1: Formula with alternative negotiation option

Workgroup member	Objective (a)	Objective (b)	Objective (c)	Objective (d)	Overall
Paul Wakeley	Yes	Yes	Yes	Neutral	Yes
Garth Graham	Yes	Neutral	Yes	Neutral	Yes
Simon Lord (Garth Graham)	Yes	Neutral	Yes	Neutral	Yes
Aled Moses	Yes	Neutral – negotiation may remove cost reflectivity	Yes	Neutral	Yes
Lewis Elder	Yes	Neutral – negotiation may remove cost reflectivity	Yes	Neutral	Yes
Joe Dunn (Garth Graham)	Yes	Neutral – negotiation may remove cost reflectivity	Yes	Neutral	Yes

WACM2: Negotiation Only

Workgroup member	Objective (a)	Objective (b)	Objective (c)	Objective (d)	Overall
Paul Wakeley	Neutral – the lack of a transparent methodology may hinder competition.	Neutral	Yes	Neutral	Yes
Garth Graham	Neutral	Neutral	Yes	Neutral	Yes
Simon Lord (Garth Graham)	Yes	Neutral	Yes	Neutral	Yes
Aled Moses	Neutral	Neutral	Yes	Neutral	Yes
Lewis Elder	Yes - negotiation may facilitate competition	Neutral	Yes	Neutral	Yes
Joe Dunn (Garth Graham)	Neutral	Neutral	Yes	Neutral	Yes

Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the Original Modification Proposal.

WACM1: Formula with alternative negotiation option

Workgroup member	Objective (a)	Objective (b)	Objective (c)	Objective (d)	Overall
Paul Wakeley	No	No	Neutral	Neutral	No
Garth Graham	Yes	Neutral	Neutral	Neutral	Yes
Simon Lord (Garth Graham)	Yes	Neutral	Neutral	Neutral	Yes
Aled Moses	No	No	Neutral	Neutral	No
Lewis Elder	No	No	Neutral	Neutral	No
Joe Dunn (Garth Graham)	Yes	Neutral	Neutral	Neutral	Yes

WACM2: Negotiation Only

Workgroup member	Objective (a)	Objective (b)	Objective (c)	Objective (d)	Overall
Paul Wakeley	No	No	Neutral	Neutral	No
Garth Graham	No	No	Neutral	Neutral	No
Simon Lord (Garth Graham)	No	No	Neutral	Neutral	No
Aled Moses	No	No	Neutral	Neutral	No
Lewis Elder	No	No	Neutral	Neutral	No
Joe Dunn (Garth Graham)	No	No	Neutral	Neutral	No

Vote 3: which option is considered to BEST facilitate achievement of the Applicable CUSC Objectives. For the avoidance of doubt, this vote should include the existing CUSC baseline as an option.

Workgroup member	Best Option
Paul Wakeley	Original
Garth Graham	WACM1
Simon Lord (Garth Graham)	WACM1
Aled Moses	Original
Lewis Elder	Original
Joe Dunn (Garth Graham)	WACM1

10 How to Respond

10.1 If you wish to respond to this Code Administrator Consultation, please use the response pro-forma which can be found under the 'Industry Consultation' tab via the following link;

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP242/

10.2 Responses are invited to the following questions;

1. Do you believe CMP242 or its alternative solution better facilitates the Applicable CUSC Objectives? Please include your reasoning.

2. Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.

3. Do you have any other comments?

10.3 Views are invited on the proposals outlined in this consultation, which should be received by **5pm** on **26th November 2015**. Please email your formal response to: CUSC.team@nationalgrid.com

10.4 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 this confidentiality. A response marked 'Private & Confidential' will be disclosed to the Authority in full by, 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 & Confidential'.

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP242

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Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal
Charging arrangements for interlinked offshore transmission solutions connecting to a single onshore substation.
Submission Date
19th March 2015.
Description of the Issue or Defect that the CUSC Modification Proposal seeks to address
A number of developers of offshore generation are planning the construction of a transmission cable linking the platforms of some of their projects that connect to a common onshore substation (held in open standby unless the cable to shore associated with either project becomes unavailable). Such a cable would provide additional security to their projects but may not necessarily provide any additional capacity, providing a cheaper alternative to building multiple cables to shore from each platform.

Whilst similar low voltage cables already exist for a number of offshore generators, these have either remained within generator ownership or exist to the supply of energy to a platform in the event of a fault rather than an export route.

However, the current charging methodology within section 14 of the CUSC would not provide a cost reflective charge for offshore transmission solutions that include interlinked offshore substations connecting to a common onshore substation. |
| **Description of the CUSC Modification Proposal** |
| It is proposed that the TNUoS charging methodology within Section 14 of the CUSC is modified to ensure that both interlinking circuits and additional capacity that can be utilised on the export cables to shore are appropriately charged, such that:

i)   The charge for capacity on an interlinking circuit that can be utilised by generation on either end of the link is set such that each party pays an amount representing an equal proportion of the associated OFTO revenue;

ii)   The charge for any capacity on an interlinking circuit that can only be utilised by a generation on one end of the link is set such that the relating generation pays a charge equivalent to the associated OFTO revenue; and |

CUSC Modification Proposal Form Charging v1.6

iii)	The Local circuit charge for an offshore generator will reflect any additional capacity on export cables to shore that is made available through use of an interlinking circuit.

Impact on the CUSC
Changes to Section 14.15 Derivation of the Transmission Network Use of System Tariff

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

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

BSC ☐

Grid Code ☐

STC ☐

Other ☐
(please specify)

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

Urgency Recommended: Yes / No
No

Justification for Urgency Recommendation
N/A

Self-Governance Recommended: Yes / No
No

Justification for Self-Governance Recommendation
N/A

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Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?
N/A

Impact on Computer Systems and Processes used by CUSC Parties:
N/A

Details of any Related Modification to Other Industry Codes
N/A

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

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.

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

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

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Full justification:

The proposed solution will ensure that the TNUoS charging methodology adequately takes account of interlinked offshore transmission solutions (better facilitating objective (c – taking developments of transmission businesses into account)). It will ensure that charges reflecting the cost of transmission assets provided as part of an interlinked solution are paid by generators benefitting from them rather than the costs being incorporated within the residual charge picked up by all generation (better facilitating applicable objectives (b - cost reflectivity) and (a - competition)).

Additional details

Details of Proposer: (Organisation Name)	National Grid Electricity Transmission plc
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	Wayne Mullins National Grid 01926 653999 wayne.mullins@nationalgrid.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Juliette Richards National Grid 01926 654580 juliette.richards@nationalgrid.com
Attachments (Yes/No): No **If Yes, Title and No. of pages of each Attachment:** n/a	

CUSC Modification Proposal Form Charging v1.6

Contact Us

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

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

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

Submitting the Proposal

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

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

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

CUSC Modification Proposal Form Charging v1.6

national grid

Workgroup Terms of Reference and Membership
TERMS OF REFERENCE FOR CMP242 WORKGROUP

CMP242 seeks to modify the CUSC to ensure that both circuits linking offshore platforms connecting to a common onshore substation and additional capacity that can be utilised on export cables to shore by offshore generation as a result are appropriately charged.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **242 'Charging Arrangements for interlinked offshore transmission solutions connecting to a single onshore substation'** tabled by National Grid Electricity Transmission Plc at the CUSC Modifications Panel meeting on 27th March 2014.

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

    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.

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

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

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

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Scope of work

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

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

   a) *Should installation of an interlink be mandatory or optional for offshore generation connecting to a common onshore substation?*
   b) *Should a generator contribute to the cost of another cable when having non-firm access to the onshore substation?*
   c) *Implementation*
   d) *Review illustrative legal text*

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

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

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

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

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of 3 weeks as determined by the Modifications Panel.

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

    As appropriate, the Workgroup will be required to undertake any further analysis and update the original Modification Proposal and/or WACMs. All responses including any WG Consultation Alternative Requests shall be

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included within the final report including a summary of the Workgroup's deliberations and conclusions. The report should make it clear where and why the Workgroup chairman has exercised his right under the CUSC to progress a WG Consultation Alternative Request or a WACM against the majority views of Workgroup members. It should also be explicitly stated where, under these circumstances, the Workgroup chairman is employed by the same organisation who submitted the WG Consultation Alternative Request.

12.   The Workgroup is to submit its final report to the Modifications Panel Secretary on 17th September 2015 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 25th September 2015.

Membership

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

Role	Name	Representing
Chairman	Patrick Hynes	Code Administrator
National Grid Representative*	Paul Wakeley	National Grid
Industry Representatives*	Garth Graham	SSE
	Aled Moses	Dong Energy
	Simon Lord	GDF Suez
	Lewis Elder	RWE Innogy UK
	Joe Dunn	SP Renewables
Authority Representatives	Edda Dirks	Ofgem
Technical secretary	Richard Loukes	Code Administrator
Observers		

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

14.   The Chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP242 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

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

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

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

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

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

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

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

Appendix 1 – Indicative Workgroup Timetable

The following timetable is indicative for CMP242

10th April 2015	Deadline for comments on Terms of Reference / nominations for Workgroup membership
1st May 2015	Workgroup meeting 1
22nd May 2015	Workgroup meeting 2
19th June 2015	Workgroup meeting 3
W/C 15th June 2015	Workgroup meeting 4
24th June 2015	Workgroup Consultation issued for 1 week Workgroup comment
1st July 2015	Deadline for comment
6th July 2015	Workgroup Consultation published
27th July 2015	Deadline for responses
W/C 3rd August 2015	Workgroup meeting 5
W/C 24th August 2015	Workgroup meeting 6
2nd September 2015	Circulate draft Workgroup Report
9th September 2015	Deadline for comment
17th September 2015	Submit final Workgroup Report to Panel
25th September 2015	Present Workgroup Report at CUSC Modifications Panel

The Workgroup first met on 1st May 2015. Further Workgroup meetings were held on 22nd May 2015 and 19th June 2015 prior to the Workgroup Consultation.The Workgroup developed the Original Proposal and two alternative proposals at their remaining meetings on 10th August 2015, 20th August 2015 and its final meeting on 4th September 2015.

The attendance record of Workgroup members is shown in the table below.

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

Name	Organisation	Role	01/05/2015	22/05/2015	19/6/2015	10/08/2015	20/08/2015	04/09/2015
Patrick Hynes	National Grid	Independent Chair (1)	A	A	A	-	-	-
Wayne Mullins			-	-	-	A	A	A
Richard Loukes/ Sharon Fellows/ Heena Chauhan	Code Administrator	Technical Secretary	A	A	A	A	A	A
Wayne Mullins	National Grid	Proposer (2)	A	-	-	-	-	-
Paul Wakeley			-	A	A	A	A	A
Garth Graham	SSE	Workgroup member	A	D	-	D	A	D
Christoph Horbelt	Dong Energy	Workgroup member (3)	A	-	-	-	-	-
Aled Moses			-	A	A	A	D	A
Simon Lord	GDF Suez	Workgroup member	A	D	D	D	A	X
Lewis Elder	RWE Innogy UK	Workgroup member	A	A	D	A	D	D
Joe Dunn	SP Renewables	Workgroup member	A	D	D	A	D	D, O (4)
Edda Dirks	Ofgem	Authority Representative	A	A	A	A	D	A

(1) The Chair changed after the third Workgroup meeting. Note: Wayne Mullins attended as Chair capacity although previously attended as Proposer, which changed to Paul Wakeley.
(2) The National Grid representative and Proposer changed after the first Workgroup meeting.
(3) The Workgroup member from DONG Energy changed after the first Workgroup meeting.
(4) For the Workgroup on 04/09/2015, Juan Benito Elvira dialled-in as an observer on behalf of Joe Dunn. Garth Graham voted on Joe Dunn's behalf.

Annex 4 – Workgroup Consultation Responses

CMP242 – Charging Arrangements for interlinked offshore transmission solutions connecting to a single onshore substation

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 31 July 2015** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Paul Wakeley at paul.wakeley@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Aled Moses (almos@dongenergy.co.uk)
Company Name:	DONG Energy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We support CMP242 and the proposals made. Our views are set out in more detail below.
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP242 Original Proposal or any of the potential options for change better facilitates the Applicable CUSC Objectives?**	Yes, in our view CMP242 better facilitates all three of the applicable CUSC objectives for Charging. (a) CMP242 facilitates competition in the generation of electricity be implementing a robust and appropriate method of allocating the cost of an offshore interlink. Without CMP242 offshore developers would have no certainty over the charges they would face for an interlink, and this would inhibit their development. By enabling offshore generators with interlinks the modification enables the development of more complex offshore networks, and through that future, more affordable offshore generators. (b) The workgroup's preferred charging methods will find ways of reasonably allocating the costs of the interlink to the generators that benefit. (c) CMP242 accurately reflects that future OFTOs will be more likely to contain interlinks.
2	**Do you support the proposed implementation approach?**	Yes, we do not see any issues with the implementation.

Q	Question	Response
3	**Do you have any other comments?**	Yes. We would like the workgroup to consider adjusting one of their key assumptions. The assumption is that "Priority for export will be given to the generator connected via the remaining main circuit, and the other generator may need to reduce their output if they wish to use the interlink to export via the remaining main circuit". Interlinked offshore generators may have agreements between themselves over how their capacity is curtailed in the case of an outage. For example, two offshore generators might have an agreement to curtail themselves equally. The charging methodologies developed as part of CMP242 are based on the assumption that priority goes to the generator connected to the main circuit. However, in our view they are still valid even if interlinked offshore generators choose to curtail themselves differently, as this will be a technical and commercial agreement made outside of the CUSC. We believe that CMP242 needs to reflect this distinction.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP224

Q	Question	Response
5	• For an existing or financially committed generator, when an interlink is proposed, should the generator have the right to 'opt-out' of paying for (and using for) interlink? • If a generator initially opts-out, but later 'opts-in' to paying for (and using) an interlink should any costs be applied retrospectively?	No, we do not think that generators should be allowed to opt-out. The situation highlighted in the report is where one generator had been built or undergone FID and as part of the design and connection of another generator an interlink is proposed. In our view this situation is highly unlikely. In addition, allowing a generator to opt-out has practical implications for the design of the offshore network and the rest of the offshore regime. If a current generator was allowed to opt-out then any interlink proposed would have to be done on the basis that it was efficient for that interlink to be in place where only one generator benefitted. While this may be allowed under the current regulatory framework it does have practical considerations. For example, would the existing generator have to confirm their opt-out during the design of the connection, years before the new generator connects? We think there are further implications for allowing a generator to opt-out then later opt-in. This would lead to a strong incentive on generators to opt-out by default and have costs placed on the other generator in the hope that they do not require the interlink. By opting-out, a generator would also let the other generator bear additional liability for the interlink and they could then opt in at a later stage when there is less risk and financial commitment required. In addition, CMP242 has not proposed any changes to the offshore substation tariffs as the workgroup has assumed that the costs and benefits arising from changes to the substation would be equal between all parties. If a generator is allowed to opt-out then this principle no longer holds and there needs to be a method for allocating the increased costs at the offshore substation to the benefitting generator.
6	Do you think that individual offshore generator parties affected by an interlink should be able to agree how to apportion the costs of that interlink between them, with the CUSC providing a fall-back methodology?	In our view the CUSC should be the default methodology. Offshore generators can then choose to have bilateral agreements between themselves if they want to modify the split of the interlink costs.

Q	Question	Response
7	Do you agree with the Workgroup's view to not charge a generator for another circuit other than their main radial circuit and their share of the interlink circuit, i.e. there is no charge for the use of the other generator's radial circuit? If not, what would you propose?	We agree. CMP242 is explicitly designed to cover situations where the radial circuit is appropriately sized for the generator it connects. As the design of the radial circuit is not impacted by the interlink, there does not need to be a charge.
8	Do you have a view on whether Option (iv) – 'shared and unshared (proportion by TEC)', Option (viii) - 'Restricted Availably Measure' or another option is the most appropriate way to apportion the costs associated with an interlink? If you prefer option (vii) a weighted sum of firm and non-firm access, what value would you propose for the weighting between firm and non-firm?	We view that (viii) Restricted Availability Measure is the most cost-reflective charging methodology proposed by the working group. The Restricted Availability Measure is the only charging methodology that accounts for the capacity of the generator, the capacity of the interlink as well as the capacity of the radial cable. We also view that considering load factors more accurately represents the expected benefit a generator would gain from an interlink, especially as interlinks may in the future connect different types of generators eg offshore wind and wave. As further evidence of why we view that (viii) is the most appropriate charging methodology we would like to highlight three scenarios, which show that (viii) is consistent with the benefit we would expect offshore generators to receive from an interlink. (iv) does not produce a split of charges that reflects how generators of different sizes benefit from an interlink. a) Where capacity of the offshore radial connections are the main constraints Generator A, Circuit A – 100MW (ALF – 60%) Interlink – 100MW Generator B, Circuit B – 200MW (ALF – 60%) In this scenario there are high load factors, leading to less spare capacity on the radial circuits. Because the two generators are of unequal size, we would expect the smaller generator, to pay more, as they would benefit the most as comparatively there is more spare capacity for them to use in the case of an outage on their radial link. (viii) reflects this and produces a 60/40 split. b) Where the capacity of offshore radial connections are not a major constraint

Q	Question	Response
		Generator A, Circuit A – 100MW (ALF – 40%) Interlink – 100MW Generator B, Circuit B – 200MW (ALF – 40%) In this scenario there are low load factors, meaning lots of spare capacity. In this situation we would expect the large generator to pay more, because as the larger generator they produce more power and can use the spare capacity of the smaller generator in the case of an outage on its radial link. (viii) reflects this and produces a 40/60 split. *c) Where the interlink is the main constraint* Generator A, Circuit A – 100MW (ALF – 40%) Interlink – 40MW Generator B, Circuit B – 200MW (ALF – 40%) In this scenario there is a small interlink, and the main constraint is its size. As a result we expect that both generators would equally benefit. (viii) reflects this and produces a 50/50 split.
9	Do you agree with the Workgroup that one party should not be directly affected by the TEC reduction caused by another (all other things being equal), meaning that a fixed proportion of the costs associated with the interlink, determined based on the initial TEC of the generators, should be fixed for a TO price control period? Do you have any comments on the consequences of this approach?	We agree with the views of the workgroup. Due to the nature of offshore generators we view that is unlikely that there will be significant changes in TEC after generators have connected. As a result we think it is appropriate that any under or over recovery is socialised, as this is likely to be minor. While we recognise that it may be possible for a generator to overstate their TEC initially to game the CMP242 changes, we view this is unlikely to either happen or be significant as the rest of the regulatory framework, such as generators needing to pay for the OFTO, would dis-incentivise overstating TEC.
10	How should the situation of more than two generators be treated? Should each interlink be treated separately, should an extension of the apportionment methodology be determined to share multiple interlink costs over multiple generators, or do you have any further options?	In our view the methodology should be extended, unless there is clear evidence or a strong argument showing that the generators would benefit disproportionately from having an interlink.

As part of this workgroup consultation we have sought to draft the report in a 'more engaging' style. If you have time we would really appreciated your thoughts whether this style is better than previous reports and any ideas for improvements.

Q	Question	Response
11	Do you consider the style of this report over previous reports an improvement and have any thoughts as to further improvements?	Yes, we view that the use of clear sections, separators, and figures has improved the readability of the report.

CMP242 – Charging Arrangements for interlinked offshore transmission solutions connecting to a single onshore substation

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 31 July 2015** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Paul Wakeley at paul.wakeley@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	Joe Dunn
	Joseph.dunn@scottishpower.com
Company Name:	ScottishPower Renewables
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP242 Original Proposal or any of the potential options for change better facilitates the Applicable CUSC Objectives?**	(a) Yes, SPR believe that CMP242 deals with the charging of a section of network otherwise not adequately covered by the existing methodologies and therefore facilitates competition. (b) Yes, as in (a) above, CMP242 seeks to address a more cost reflective position to charging for interlinks (c) Yes, as the same accounts for the developments in offshore transmission network.
2	**Do you support the proposed implementation approach?**	Yes, SPR support the proposed implementation approach.
3	**Do you have any other comments?**	Not at this time.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to* cusc.team@nationalgrid.com

Specific questions for CMP224

Q	Question	Response

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[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Q	Question	Response
5	• For an existing or financially committed generator, when an interlink is proposed, should the generator have the right to 'opt-out' of paying for (and using for) interlink? • If a generator initially opts-out, but later 'opts-in' to paying for (and using) an interlink should any costs be applied retrospectively?	Yes. SPR believe that an existing (or financially committed) generator should have the option of opting out. The reason is to avoid the risk of the existing generator becoming economically unviable. Whilst it is appreciated that an interlink would only be proposed where there is an overall economic and efficiency benefit identified, it is not clear the involvement that the existing generator would have in this decision making process. For example, could SO and Ofgem decide without agreement of the existing generator that an interlink is overall economically efficient, i.e. Who confirms the data, metrics, assumptions, etc. for a cost benefit? What if the existing generator disagreed? Could they be overruled? Under the non-right to opt-out option, how/ who would cover the (then sunk) costs for the first generator in the event of the second generator terminating? Yes, in principle if a generator opts-out and later opts in then costs should be applied retrospectively. A few points to consider which may weight the argument: • Would the generator be opting in of their own volition or could this be on request from the SO? • Would there be visibility of the rolling (increasing) retrospective costs to provide the potentially opting-in generator to consider their options economically? • Could a retainer be considered to allow the existing generator to opt-in at a future date? SPR appreciate the note on behavioural concerns (noted in 2.21), however, believe that the existing generator would have to have good reason not to opt-in given that the argument for this option is that it will only be proposed where an overall economic and efficient solution has been confirmed.

Q	Question	Response
6	Do you think that individual offshore generator parties affected by an interlink should be able to agree how to apportion the costs of that interlink between them, with the CUSC providing a fall-back methodology?	Yes. SPR consider this to be a sensible approach that would allow any unique parameters (such as cable design options) to factor into the principles of apportionment. Equally, developers may have non-standard considerations that might not fit into a fixed methodology. Should there be difficulty in reaching a solution, the CUSC should provide a back-up methodology.
7	Do you agree with the Workgroup's view to not charge a generator for another circuit other than their main radial circuit and their share of the interlink circuit, i.e. there is no charge for the use of the other generator's radial circuit? If not, what would you propose?	Yes. Given the assumptions listed in 2.35, SPR agree with the workgroup's view.
8	Do you have a view on whether Option (iv) – 'shared and unshared (proportion by TEC)', Option (viii) - 'Restricted Availably Measure' or another option is the most appropriate way to apportion the costs associated with an interlink? If you prefer option (vii) a weighted sum of firm and non-firm access, what value would you propose for the weighting between firm and non-firm?	SPR's view is that Option (viii) is the most appropriate way to apportion the interlink. Whilst the arithmetic is not a simple as that in option (iv), we believe there is a requirement to reflect different load factors and capacities to shore.
9	Do you agree with the Workgroup that one party should not be directly affected by the TEC reduction caused by another (all other things being equal), meaning that a fixed proportion of the costs associated with the interlink, determined based on the initial TEC of the generators, should be fixed for a TO price control period? Do you have any comments on the consequences of this approach?	Yes, SPR agree with the workgroup's approach that a party should not be affected by another party's TEC reduction. In terms of the consequences in 2.54, there is a concern that a TEC increase would mean over charging and essentially an over recovery and also that a decrease could encourage gaming. Is there another option that could flex the tariff against a fixed portion of the interlink whereby the TEC multiplied by the tariff recovers the same total fixed amount?

Q	Question	Response
10	How should the situation of more than two generators be treated? Should each interlink be treated separately, should an extension of the apportionment methodology be determined to share multiple interlink costs over multiple generators, or do you have any further options?	SPR believe that an extension of the apportionment methodology be determined to share multiple interlink costs over multiple generators. Our opinion assumes that the same key assumptions and principles are applied, particularly in relation to the timing of the decision of an interlink(s) (being economic and efficient) and therefore taking into account all three projects.

As part of this workgroup consultation we have sought to draft the report in a 'more engaging' style. If you have time we would really appreciated your thoughts whether this style is better than previous reports and any ideas for improvements.

Q	Question	Response
11	Do you consider the style of this report over previous reports an improvement and have any thoughts as to further improvements?	Yes. Considering the complexity the report reads and flows well.

CMP242 – Charging Arrangements for interlinked offshore transmission solutions connecting to a single onshore substation

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses by **5pm on 31 July 2015** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Paul Wakeley at paul.wakeley@nationalgrid.com.

These responses will be considered by the Workgroup at their next meeting at which members will also consider any Workgroup Consultation Alternative Requests. Where appropriate, the Workgroup will record your response and its consideration of it within the final Workgroup Report which is submitted to the CUSC Modifications Panel.

Respondent:	*Garth Graham (garth.graham@sse.com)*
Company Name:	*SSE*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	
Do you believe that the proposed original or any of the alternatives better facilitate the Applicable CUSC Objectives? Please include your reasoning.	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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP242 Original Proposal or any of the potential options for change better facilitates the Applicable CUSC Objectives?**	CMP242 Original, if it led to existing generation projects being denied the opportunity choose to pay for (and use) the interlink will not better facilitate the applicable Charging Objective (a) as regards effective competition in generation as it will (i) render those generators less economic and competitive retrospectively and (ii) increase regulatory risk that other retrospective changes could occur in the future which render existing generators uneconomic.
2	**Do you support the proposed implementation approach?**	We note and support the proposed implementation approach set out paragraphs 3.5-3.6.
3	**Do you have any other comments?**	In respect of the generator own build / Authority transfer value situation (as noted in paragraph 2.24-2.25) we note that if a proportion of the assets are required (by the Authority) to be transferred (by the generator to the OFTO) at less than their actual cost and then the proportion of the assets are subsequently utilised as a result of the interlink then there will need to be either a refund to the generator of the value of the proportion of the assets transferred (where no value was initially transferred) or an ongoing payment /charge reduction for that generator to reflect the utilisation of that proportion of the assets initially not valued when transferred. To do otherwise could be in breach of EU law (such as Article 1 of the First Protocol of the European Convention on Human Rights).
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to* cusc.team@nationalgrid.com

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[1] http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/forms_guidance/

Specific questions for CMP224

Q	Question	Response
5	• For an existing or financially committed generator, when an interlink is proposed, should the generator have the right to 'opt-out' of paying for (and using for) interlink? • If a generator initially opts-out, but later 'opts-in' to paying for (and using) an interlink should any costs be applied retrospectively?	We note the Workgroup deliberations in paragraphs 2.10-25. It is vital that an existing or financially committed generator is allowed to choose to 'opt-out' of paying for (and using) an interlink. The main reason for this is that unlike potentially similar situations onshore, the quantum of the cost(s) for an offshore interlink to be paid by an existing offshore generator are likely to be many time larger than those that may possibly arise with a potentially similar situation onshore. This is due to, for example, (i) the cost of offshore cabling (compared to onshore OHL), (ii) the cost of installing / maintaining the said cabling (compared to onshore OHL); and (iiii) the costs associated with the platform(s) associated with interlink (costs which do not arise with the onshore situation). This is recognised by the Workgroup at paragraph 2.50. Given this the aligning of the onshore and offshore regimes is inappropriate. Having financially committed (or indeed constructed and commissioned) an existing generator on the basis of a known / understood set of costs (along with an appreciation of the change in those costs in the medium and long term) if additional, substantial, cost items which could not reasonably have been foreseen are then applied to that existing generator (retrospectively) then it can render the project (1) uncompetitive and (2) uneconomic. Allowing an 'opt-out' enables that existing generator to consider and model the likely cost impacts associated with the interlink on their project and determine if those costs are (or are not) outweighed by the additional benefits (if any) that they would receive from utilising the interlink. This 'opt-out' is not required, per se, for the still to be developed generator as they will know the cost(s) and impact that building the interlink will have on their project prior to them financially committing to their project. If the cost(s) and impacts render the project (1) uncompetitive and (2) uneconomic then they would not proceed with the project – an option that is not available for the existing generator. It seems reasonable, proportionate and fair that if an existing generator initially 'opts-out' but later decides to 'opt-in' to using the interlink that they should then pay their share of the associated costs of that interlink, and that this includes the costs to date, as well as those going forward, to avoid a party only opting in if / when, for example, their cable to shore fails.

Q	Question	Response
6	Do you think that individual offshore generator parties affected by an interlink should be able to agree how to apportion the costs of that interlink between them, with the CUSC providing a fall-back methodology?	We agree that the proposed approach of allowing parties to seek to agree amongst themselves initially; with a fall-back methodology of allocation in the CUSC; seems a reasonable, proportionate and pragmatic way to proceed.
7	Do you agree with the Workgroup's view to not charge a generator for another circuit other than their main radial circuit and their share of the interlink circuit, i.e. there is no charge for the use of the other generator's radial circuit? If not, what would you propose?	We note the point made in paragraph 2.35 that "The interlink is only used in the situation of faults or outages and it is not capacity that can be used or guaranteed." This is the key factor when considering if a generator using the other generator's radial cable (by way of the interlink) should or should not be charged for the use of that other generator's radial cable. Based on the above statement in the Workgroup report we agree that there should be no charge for the use of the other generator's radial cable. However, if a generator is to use the other generator's radial cable out with situations of faults or outages then that generator must pay a commensurate share of the annual tariff of the other generator's radial cable. Furthermore, if the generator using the other generator's radial cable receives a refund (due to a fault / outage situation) from its OFTO in respect of the charge(s) associated with the capacity on its radial circuit, whilst at the same time using some of the capacity of the other generator's radial cable a question may arise as to whether (at that time) it is paying a cost reflective charge for that capacity, or 'free-riding' which, if this was the case, would not better facilitate Applicable Charging Objectives (a) and (b); run counter to the Transmission Licence obligations; and potentially contravene EU Law (714/2009 and 72/2009).

Q	Question	Response
8	Do you have a view on whether Option (iv) – 'shared and unshared (proportion by TEC)', Option (viii) - 'Restricted Availably Measure' or another option is the most appropriate way to apportion the costs associated with an interlink? If you prefer option (vii) a weighted sum of firm and non-firm access, what value would you propose for the weighting between firm and non-firm?	In respect of Option (iv) this has the beneficial attributes of Option (iii) with a further refinement that the shared element is allocated on a TEC basis. In respect of Option (viii) we cannot see the benefits accruing to the two generators where; given their proximity and likely similar generation technology; an ALF based charge would practically work when, on the day, the load factor of each generator exceeds 50%. There is a danger that the generators are, in those circumstances charged for something they cannot fully utilise (but which they are paying for). In respect of Option (vii) we share the Workgroup's concerns about the arbitrary nature of the weighting(s).
9	Do you agree with the Workgroup that one party should not be directly affected by the TEC reduction caused by another (all other things being equal), meaning that a fixed proportion of the costs associated with the interlink, determined based on the initial TEC of the generators, should be fixed for a TO price control period? Do you have any comments on the consequences of this approach?	We note the deliberations of the Workgroup on this matters (as set out in paragraphs 2.49-2.54). Fixing the amount per Price Control period based on the initial TEC of the generators seems reasonable – the under recovery falling onto the residual is in line with the onshore approach. A hybrid 'cap & floor' approach would be difficult to implement, complex and be inconstant with the rest of the charging methodology. We note the consequences in paragraph 2.54 – in respect of the second item. We observe that overstating your TEC itself has consequences, such as it could lead to a higher radial main cable being built for you (and thus charged to you). Having considered the matter in the round we agree with the Workgroup proposed approach.

Q	Question	Response
10	How should the situation of more than two generators be treated? Should each interlink be treated separately, should an extension of the apportionment methodology be determined to share multiple interlink costs over multiple generators, or do you have any further options?	In principle the two interlinks (AB and BC) should be treated separately unless, for example, Generator A can, via interlinks AB and BC, use Circuit C (or vice versa, Generator C can use Circuit A) Thus if all three generators can, via the two interlinks (AB and BC), use Circuits A, B and C then the methodology should deal with cost allocation of the two Interlinks (AB and BC) between the three Generators (A-C).

As part of this workgroup consultation we have sought to draft the report in a 'more engaging' style. If you have time we would really appreciated your thoughts whether this style is better than previous reports and any ideas for improvements.

Q	Question	Response
11	Do you consider the style of this report over previous reports an improvement and have any thoughts as to further improvements?	

Annex 5 – Guide to TNUoS Charging Methodology for Offshore Generation in GB

This section is included at the request of Workgroup members, prepared by National Grid, to help the reader understand the background to the Offshore Charging Methodology in GB

The Transmission Network Use of System Charges (TNUoS) allows Transmission Owners to recover the costs of building, owning and maintaining transmission assets; be they located onshore or offshore. The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provider to Users when services are priced to reflect the cost of supplying them (CUSC 14.14.6).

For offshore generation, the TNUOS charges recover the cost of building, owning and maintaining transmission assets required to connect an offshore generator to the onshore transmission system. The TNUoS charge recovers revenue for the Offshore Transmission System Operators (OFTO) and for the onshore Transmission Owners (TO). Both OFTOs and Onshore TOs are required to hold an electricity transmission licence as defined in the Electricity Act 1989.

The **TNUoS Charging Methodology** is defined in Section 14 of the **Connection and Use of System Code (CUSC)**. The methodology applied to offshore generation is based on the methodology used for onshore generation; however, the specificities of the costs, design and regime for offshore generation is reflected in the charging methodology as detailed below.

Design of offshore connections

The design criteria for the GB Transmission Network are defined in the (GB) Security and Quality of Supply Standard (SQSS). The SQSS specifies the Offshore Standard Design as the specification that is to be used to connect an offshore generator to the National Electricity Transmission System. The criteria for offshore design are different to those for the onshore transmission network and allow a lower level of redundancy. This difference, seeks to partly offset the high costs of building and maintaining offshore circuits and substations.

In general under the Offshore Standard Design, an offshore generator will be connected to the transmission network via a single radial circuit via an offshore and onshore OFTO substation. This general setup is illustrated in the following diagram:
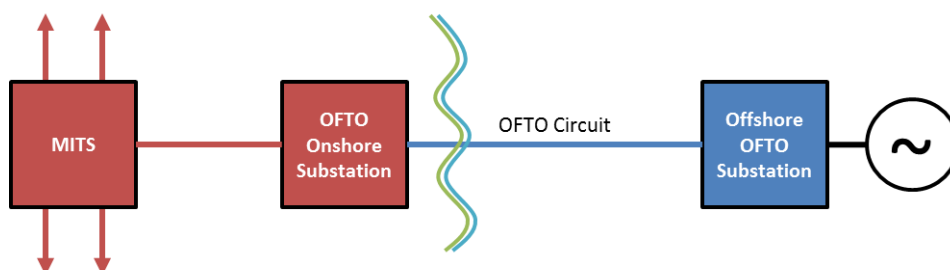
The capacity of the OFTO circuit and the ratings of any of the equipment in the substations (e.g. transformers, switchgear) are chosen to support the connected generation, whilst generally being of standard sizes available on the market to reduce the additional costs of bespoke equipment. This result in potentially larger capacity equipment, such as transformers, being installed that the TEC capacity of the generator being connected.

In certain circumstances, the offshore generator will also be liable for an onshore circuit charge if the OFTO onshore substation is connected to the Main Integrated Transmission System (MITS) via a non-MITS substation. If the connection to the MITS is via a distribution circuit, then a distribution charge will also be levied.

A particular feature of the offshore single-circuit radial design is that there is no redundancy provided to the generator in the event of a circuit or other fault. As this is a known factor, and consistent with the approved position in the SQSS, the circumstances when an offshore generator is liable for compensation, known as interruption payments in the CUSC, are different to onshore generators.

Interruption Payments and Compensation

As defined in Section 5 of the CUSC (Default, Deenergisation and Disconnection) a generator becomes eligible for an *Interruption Payment* in the event of a Relevant Interruption. Relevant Interruption are defined as an Interruption other an *Allowed Interruption*.

One of the requirements for having a standard offshore design is the inclusion of Clause 10 in the Bilateral Connection Agreement (BCA) for the generator. Clause 10 provides that outages associated with a single radial circuit are considered 'Allowed Interruptions'. This means that offshore generators are not eligible for Interruption Payments under the CUSC for circuit outages and/or restrictions associated with a single radial circuit design.

An offshore generator may decide to pay more for their connection to have additional security (such as another circuit) included in their transmission connection design. Ultimately, Ofgem decides what elements of an offshore design are permitted, when assets are transferred and the allowable revenue is determined. Subject to approval, this additional security would be reflected in their circuit charge. In this situation, different criteria would apply in the BCA which may allow for interruption payments in the event of some outages, for example, in general configuration other than a single circuit (such as a double circuit) may mean a generator would be eligible for a CUSC Interruption Payment if that circuit were unavailable, but these would be agreed on a case-by-case basis based the individual scenario.

Although offshore generators who have a Clause 10 BCA cannot claim a CUSC Interruption Payment associated with outages of their radial circuits, the licence for an OFTO includes an *availability incentive* requiring them to achieve a 'target availability' for their circuit. OFTOs are incentivised to achieve these figures and are penalised for failing to achieve it. The precise formulation of the target is different for the different tender rounds of OFTOs but the overall principle remains the same.

If an OFTOs fail to meet their target availability as specified in their licence, then their allowed revenue would be reduced, however, this will not directly affect the generators tariff due to the way in which offshore tariffs are set.

Charging methodology for an offshore generator

The TNUoS tariff for an offshore generator is composed of several parts:

- The **offshore substation tariff** – related to the assets at the offshore substation, specific to the generator

- The **offshore circuit tariff** – related to the cost of the OFTO circuit, specific to the generator

- The **wider tariff associated** with the use of the Main Interconnected Transmission System

Depending on their type of connection, offshore generators may also pay for a local onshore circuit (if there is such a circuit prior to the MITS), and for connection via a distribution system.

In common with the onshore charging methodology an offshore generator only pays onshore substation charges associated with the first substation they are connected to. The costs of the OFTO Onshore substation are socialised into the wider tariff element of TNUoS.
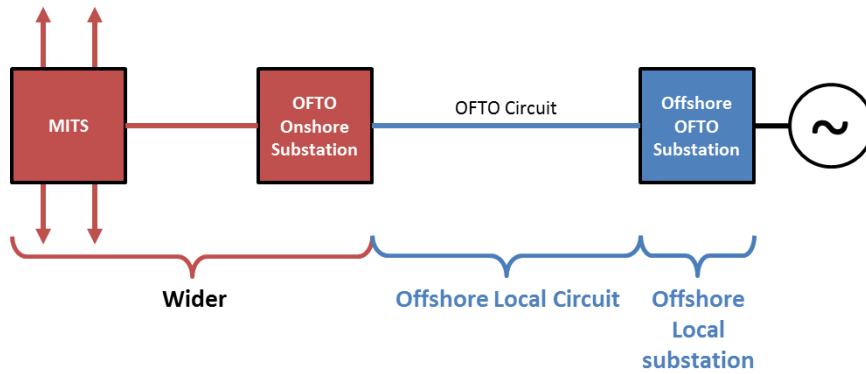
OFTO Revenue

The amount of money to be recovered through TNUoS for an OFTO in a given charging year is termed its 'revenue'. National Grid pays this revenue to the OFTO and then seeks to recover it via TNUoS Charges from the User(s) in accordance with the charging methodology.

To calculate the offshore substation tariff and the offshore local circuit tariff applicable to a generator, the OFTO revenue is first tagged to the specific radial circuit and offshore substation that it relates to. Any revenue not captured through these offshore substation and offshore local circuit tariffs is included in the wider tariff which socialises the remaining revenue.

On page 77is a worked example for a fictional OFTO and generator. In this example there is a offshore generator connected via a single radial OFTO circuit. The generator has TEC of 400MW, and the single radial circuit has capacity of 420MW. The fictional OFTO has a revenue of £25M per annum.

Local offshore circuit tariff

The amount of revenue attributed to the offshore circuit tariff is the OFTO revenue multiplied by the ratio of the circuit capital cost to the total capital cost.

In the worked example the capital cost of the circuit is £116M and the total capital cost is £303.5M; the proportion of the capital cost of the circuit (to the total capital cost) is therefore 38%. The total revenue is £25M, so the proportion of the revenue associated with the circuit is therefore, 38% x £25M = £9.55M.

The local security factor (LSF) is a scaling factor included to represent the additional cost associated with the benefit of having redundancy in a design. If there is a single radial circuit (i.e. the standard offshore design), then the local security factor is 1. If there are multiple electrically connected circuits, then the local security factor is calculated as:

$$LSF = \frac{\text{Maximum Export Capacity of Circuits}}{\text{Generator TEC}}.$$

The Local Security Factor is capped at 1.8; the same as the onshore security factor.

The *local offshore circuit tariff* is calculated as:

$$\text{local offshore circuit tariff} = \text{local security factor} \times \frac{\text{OFTO Revenue}}{\text{Circuit Rating}}.$$

In the worked example, as we have a single circuit, the LSF is 1.

The local offshore circuit tariff = 1 x £9.55M / 420 MW = **22.750451 £/kW**.

Local offshore substation tariff

The offshore substation tariff is calculated to be representative of the cost of the Transformer, Switchgear and Platform at the offshore OFTO substation.

The amount of revenue attributed to the offshore substation tariff, is the OFTO revenue multiplied by the ratio of the substation capital cost to the total capital cost. This calculation is performed for each element of the substation (Transformer, Switchgear and Platform).

In the worked example, for the Transformer element the capital cost is £10M and the total capital cost of the work is £303.5M; the proportion of the capital cost of the Transformer (to the total capital cost) is therefore 3%.

The proportion of the revenue associated with the Transformer is therefore, 3% x £25M = **£823k**.

Similarly the revenue associated with of each element of the offshore substation is calculated as a proportion of the total capital costs.

The tariff is calculated by dividing the revenue for each item by its rating (MVA). This gives a tariff for each of the Transformer, Switchgear and Platform.

The local offshore substation tariff is the sum of the Transformer, Switchgear and Platform less the onshore civils cost adjustment. The onshore civil cost adjustment is a reduction to the offshore substation tariff. Onshore local circuit tariffs do not include civils cost, so this discount seeks to align the local circuit tariffs.

In the worked example, the local offshore substation tariff is **17.273804 £/kW**

Final Tariff

The final tariff for an offshore generator is the sum of (i) the local offshore substation tariff, (ii) the local offshore circuit tariff, (iii) any onshore local circuit tariffs[9], and (iv) the wider generator tariff. The wider tariff is applied based on which of the 27 TNUoS zones the generator is connected to and is detailed in the National Grid Charging Statements.

For this worked example, let us assume a connection in Zone 17 (South Lincs and North Norfolk) which has a wider generation tariff of **2.974367 £/kW.**

For this worked example the final tariff is therefore = 22.750451 + 17.273804 + 2.974367 = **42.998622 £/kW**

Therefore, the annual TNUoS charge to this hypothetical offshore generator with TEC of 400MW connecting in the South Lincs and North Norfolk zone is 400 MW x 42.998622 £/kW = **£17.2M**

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[9] Not applicable in this worked example

Worked Example

In this example, the Total Revenue for the OFTO is £25M, and the Generator TEC is 400 MW connected in TNUoS Zone 17.

		Capital Cost	Percentage of Total Capital Costs	Amount of OFTOt	Rating / Capability	Local Security Factor	Tariff
		(£k)		(£)	(MVA)		(£/kW)
Circuit	Offshore cable	100,000					
	Harmonic filtering equipment	1,000					
	Reactive plant	15,000					
	Circuit	**116,000**	**38%**	**9,555,189**	**420**	**1**	**22.750451**
Substation	Transformer	10,000	3%	823,723	640		1.287068
	Switchgear	2,500	1%	205,931	680		0.302839
	Platform	125,000	41%	10,296,540	640		16.088344
	Onshore civils cost adjustment						-0.404447
	Substation	**137,500**	**45%**	**11,326,194**			**17.273804**
Other	Onshore substation	50,000	16%	4,118,616			Not Applicable
	Other	**50,000**	**16%**	**4,118,616**			Not Applicable
	TOTAL CAPITAL COST	**303,500**					

Total Local Tariff	40.024255
Wider Generator Tariff	2.974367
TOTAL TARIFF	**42.998622**

Table 6: *Worked example for deriving offshore charges for a generator*

Local Circuit Tariff as defined in CUSC

In the CUSC, the offshore local circuit charge calculations are defined differently to the approach detailed in this paper. However, the two results are mathematically equivalent due to the particular circumstances of offshore generation.

According to the CUSC, the local circuit tariff is calculated as

$$\text{Local Circuit Tariff } (\pounds/kW) = \text{NLMkm} \times \text{EC} \times \text{LocalSF} \div 1000.$$

NLMkm is the Nodal marginal km along the local circuit using local circuit expansion factor. One of the key elements of the charging methodology is the transport model, used to calculate marginal costs. The local marginal km cost used to determine generation TNUoS tariffs is calculated by injecting 1MW of generation against the node the generator is modelled at and increasing national demand by 1MW and calculating the effect.

EC is the **expansion constant**. This represents the annuitized value of the capital investment required to transport 1MW over 1km. Its magnitude is derived from the project cost of 400kV overhead line. As calculated at the TO price control review, this is 12.901218 £/MWkm,

For an offshore radial local circuit

For an offshore radial local circuit, there is only one possible route for electricity to reach the main network; therefore it is not necessary to run the full transport model to calculate the increase in the circuit km cost since 1MW can only travel along the length of the subsea cable. The marginal cost increase of 1MW of offshore generation can therefore be calculated as:

$$\text{NLMkm} = \text{Expansion Factor} \times \text{Length},$$

where the expansion factor is defined in the CUSC based on information provided by the OFTO; it reflects how much more expensive subsea cable is compared to 400kV overhead line:

$$\text{Expansion Factor} = \frac{\text{OFTO Revenue}}{\text{Length} \times \text{Circuit Rating}} \div \text{Expansion Constant}.$$

In the worked example assuming a cable length of 50km, we find that:

Expansion Factor $\quad$ = £9.5M ÷ (420 MW × 50 km) ÷ 12.901218 = 35.26869

This means that the subsea cable is 35 times more expensive than 400kV overhead line.

Local Circuit Tariff $\quad$ = 50 km × 35.26869 × 12.901218 × 1 ÷ 1000 = 22.75045 £/kW

Mathematical equivalence for offshore radial local circuits

Using this definition of Offshore Expansion Factor, the definition of Local Circuit tariff and the value of NLMkm, it can be demonstrated that the Local Circuit Tariff definition in the CUSC is equivalent to the method used in this paper:

$$
\begin{aligned}
\text{Local Circuit Tariff } (\pounds/kW) &= NLMkm \times EC \times LocalSF \div 1000 \\
&= (\text{Expansion Factor} \times \text{Length}) \times EC \times LocalSF \div 1000 \\
&= \frac{\text{OFTO Revenue}}{\text{Length} \times \text{Circuit Rating} \times EC} \times \text{Length} \times EC \times LocalSF \div 1000 \\
&= \frac{\text{OFTO Revenue}}{\text{Circuit Rating}} \times LocalSF \div 1000.
\end{aligned}
$$

	Apportionment Option	Mathematical definition
i	Equal Split	Proportion for each generator = $1/n$ where n is the number of generators
ii	Proportion of TEC	Proportion for each generator = $TEC_X / \sum_{\text{All generators } j} TEC_j$

iii	Shared and Unshared (equal)	<u>Proportion for Generator A =</u> (0.5 x Shared + A Only)/ (Shared + A Only + B Only)
		<u>Proportion for Generator B =</u> (0.5 x Shared + B Only) / (Shared + A Only + B Only)
		Where Shared = $\min(TEC_A, CAP_I, TEC_B)$
		          A Only = $\max(0, CAP_I - TEC_B)$
		          B Only = $\max(0, CAP_I - TEC_A)$

iv	Shared and Unshared (proportion of TEC)	<u>Proportion for Generator A =</u> (P_A x Shared + A Only)/ (Shared + A Only + B Only)
		<u>Proportion for Generator B =</u> (P_B x Shared + B Only)/ (Shared + A Only + B Only)
		Where $P_A = TEC_A / (TEC_A + TEC_B)$
		          $P_B = TEC_B / (TEC_A + TEC_B)$
		          And definitions in iii.

v	Additional Firm Access	<u>Proportion for Generator A =</u> (A via CCT B) / (A via CCT B + B via CCT A) <u>Proportion for Generator B =</u> (B via CCT A) / (A via CCT B + B via CCT A) *Where* A via CCT B = $\min(CAP_B - TEC_B, CAP_I, TEC_A)$ B via CCT A = $\min(CAP_A - TEC_A, CAP_I, TEC_B)$
vi	Non-firm access using ALF	<u>Proportion for Generator A =</u> (A via CCT B) / (A via CCT B + B via CCT A) <u>Proportion for Generator B =</u> (B via CCT A) / (A via CCT B + B via CCT A) *Where* <u>A via CCT B</u> = $\min(CAP_B - ALF_B \text{ x } TEC_B, CAP_I, TEC_A)$ – Firm Access via CCT B <u>B via CCT A</u> = $\min(CAP_A - ALF_A \text{ x } TEC_A, CAP_I, TEC_B)$ – Firm Access via CCT A Firm Access via CCT X is the value calculated as "where" in (v).
vii	Combination of Firm and Non-Firm	<u>Proportion for Generator A =</u> (w x firm$_A$ + (1-w) x non-firm$_A$)/ (w x (firm$_A$ + firm$_B$) + (1-w) x (non-firm$_A$ + non-firm$_B$) <u>Proportion for Generator B =</u> (w x firm$_B$ + (1-w) x non-firm$_B$)/ (w x (firm$_A$ + firm$_B$) + (1-w) x (non-firm$_A$ + non-firm$_B$) where *w* is a weighting to be determined, and firm$_X$ and non-firm$_X$ are the values of capacity calculated options (v) and (vi)
viii	Restricted Availability Measure (using ALF)	<u>Proportion for Generator A =</u> (A via CCT B) / (A via CCT B + B via CCT A) <u>Proportion for Generator B =</u> (B via CCT A) / (A via CCT B + B via CCT A) *Where* A via CCT B = $\min(CAP_B - ALF_B \text{ x } TEC_B, CAP_I, ALF_A \text{ x } TEC_A)$ B via CCT A = $\min(CAP_A - ALF_A \text{ x } TEC_A, CAP_I, ALF_B \text{ x } TEC_B)$

Annex 7 - Updated Offshore Local Security Factor – Mathematical Note

In order to demonstrate that this updated Local Security Factor results in an offshore generator with an interlink paying the correct amount in charges, consider the following scenarios.

(a) Assuming we have a generator which has a main circuit of *Rating* MW and OFTO circuit revenue of £ *CRev,* and Transmission Entry Capacity of *TEC* MW*,* then without an interlink, the local circuit tariff will be

$$\text{Local Circuit Tariff} = LSF_i \times \frac{CRev}{Rating}.$$

(b) Where LSF$_i$ is the Local Security Factor as defined in the CUSC. For a single circuit it is 1, for multiple circuits it is the total export capacity divided by TEC, capped at 1.8.

(c) The amount paid by the generator is the Local Circuit Tariff multiplied by TEC, so:

$$\text{Local Circuit Charge} = LSF_i \times \frac{CRev}{Rating} \times TEC.$$

Now consider if the same generator also needs to pay there proportion of the interlink revenue, termed £ *IRev.*

(d) With an interlink the definition of Local Security Factor is updated to:

$$LSF = \frac{IRev \times Rating}{CRev \times TEC} + LSF_i.$$

(e) Therefore, a generator with an interlink revenue to pay of IRev, will pay a total of

$$
\begin{aligned}
\text{Local Circuit Charge} &= LSF \times \frac{CRev}{Rating} \times TEC \\
&= \left[\frac{IRev \times Rating}{CRev \times TEC} + LSF_i\right] \times \frac{CRev}{Rating} \times TEC. \\
&= \frac{IRev \times Rating}{CRev \times TEC} \times \frac{CRev}{Rating} \times TEC + LSF_i \times \frac{CRev}{Rating} \times TEC. \\
&= IRev + \left(LSF_i \times \frac{CRev}{Rating} \times TEC\right).
\end{aligned}
$$

(f) That is the revenue associated with the OFTO interlink (IRev), and the normal circuit revenue without the interlink.

The numbering refers to current version of the CUSC, version v 1.10 – 01 April 2015. The numbering may need to be adjusted to account for changes to Section 14 arising from the implementation of CMP213 and other modifications.

Original Proposal

Insert text after 14.15.63 (Offshore Circuit Expansion Factors)

Offshore Interlinks

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

Where:

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

A *Single Common Substation* is a substation where:

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

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

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

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

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

and

Cap_{IAB} = total capacity of the Offshore Interlink between substations A and B
Cap_{IBC} = total capacity of the Offshore Interlink between substations B and C
Cap_X = total capacity of the circuit between offshore substation X and the Single Common Substation, where X is A, B or C.
$RCap_X$ = remaining capacity of the circuit between offshore substation X and the Single Common Substation in the event of a single cable fault, where X is A, B or C.
TEC_X = the sum of the TEC for the Users connected, or contracted to connect, to offshore substation X, where X is A, B or C, where the value of TEC will be the maximum TEC that each User has held since the initial charging date, or is contracted to hold if prior to the initial charging date.
ILF_X = Offshore Interlink Load Factor, where X is A, B or C.
The Offshore Interlink Load Factor (ILF) is based on the Annual Load Factor (ALF). Until all the Users connected to a Single Common Substation have a power station specific Annual Load Factor based on five years of data, the generic ALF for the plant type will be used as the ILF for all power stations. When all Users have a power station specific ALF, the value of the ALF in the first such year will be used as the ILF in the calculation for all subsequent charging years.

14.15.65 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.64 applies in situations where the interlink was included in the design phase, or if one or more User has already financially committed or been commissioned then only where that the User(s) agrees to the interlink.

The Locational Onshore Security Factor

14.15.64 14.15.66 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.65 14.15.67 The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.66 14.15.68 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 and fixed for the duration.

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

Local Security Factors

14.15.67~~14.15.69~~   Local onshore security factors are generator specific and are applied to a generators local onshore circuits. 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 redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.68~~14.15.70~~   A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

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

Where:

NetworkExportCapacity =   the total export capacity of the network disregarding any Offshore Interlinks

k   =   the generation connected to the offshore network

14.15.69~~14.15.71~~   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, derived as 1.8 for 2010/11.

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

$$LocalSF = \frac{IRevOFTO \times NetworkExportCapacity}{CRevOFTO \times \sum_k Gen_k} + LocalSF_{initial}$$

Where:

IRevOFTO =   The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.64

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

LocalSF_{initial} =   Initial Local Security Factor calculated in 14.15.70 and 14.15.71
And other definitions as in 14.15.70.

The remaining paragraphs in Section 14.15 (originally 14.15.70 to 14.15.103) are to be renumbered to 14.52.73 to 14.15.106.

Insert text after 14.15.63 (Offshore Circuit Expansion Factors)

<u>Offshore Interlinks</u>

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

Where:

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

A *Single Common Substation* is a substation where:
  i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
  ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

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

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

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

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

and

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

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

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

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

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

ILF_X = Offshore Interlink Load Factor, where X is A, B or C.

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

14.15.65 The apportionment of revenue associated with Offshore Interlink(s) in 14.15.64 applies in situations where the interlink was included in the design phase, or if one or more User has already financially committed or been commissioned then only where that the User(s) agrees to the interlink.

14.15.66 Alternatively to the formula specified in 14.15.64 the proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink may be agreed between these Users. In this event:

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

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

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

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

The Locational Onshore Security Factor

14.15.64 14.15.67 The locational onshore security factor is derived by running a secure DCLF ICRP transport study based on the same market background as used in the DCLF ICRP transport model. This calculates the nodal marginal costs where peak demand can be met despite the Security and Quality of Supply Standard contingencies (simulating single and double circuit faults) on the network. Essentially the calculation of secured nodal marginal costs is identical to the process outlined above except that the secure DCLF study additionally calculates a nodal marginal cost taking into

account the requirement to be secure against a set of worse case contingencies in terms of maximum flow for each circuit.

14.15.65 14.15.68   The secured nodal cost differential is compared to that produced by the DCLF ICRP transport model and the resultant ratio of the two determines the locational security factor using the Least Squares Fit method. Further information may be obtained from the charging website[1].

14.15.66 14.15.69   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 and fixed for the duration.

Local Security Factors

14.15.67 14.15.70   Local onshore security factors are generator specific and are applied to a generators local onshore circuits. 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 redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

14.15.68 14.15.71   A specific offshore local security factor (LocalSF) will be calculated for each offshore connection using the following methodology:

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

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

14.15.69 14.15.72   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, derived as 1.8 for 2010/11.

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

$$LocalSF = \frac{IRevOFTO \times NetworkExportCapacity}{CRevOFTO \times \sum_k Gen_k} + LocalSF_{initial}$$

Where:
IRevOFTO =   The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.64

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

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

LocalSF$_{initial}$ = Initial Local Security Factor calculated in 14.15.71 and 14.15.72
And other definitions as in 14.15.71.

The remaining paragraphs in Section 14.15 (originally 14.15.70 to 14.15.103) are to be renumbered to 14.52.74 to 14.15.107.

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Insert text after 14.15.63 (Offshore Circuit Expansion Factors)

Offshore Interlinks

14.15.64 The revenue associated with an Offshore Interlink shall be divided entirely between those generators benefiting from the installation of that Offshore Interlink. Each of these Users will be responsible for their charge from their charging date, meaning that a proportion of the Offshore Interlink revenue may be socialised prior to all relevant Users being chargeable. The proportion associated with each generator will be decided by negotiation between the relevant Users.

Where:

An *Offshore Interlink* is a circuit which connects two offshore substations that are connected to a Single Common Substation. It is held in open standby until there is a transmission fault that limits the generators ability to export power to the Single Common Substation. In the Transport Model, they are to be modelled in open standby.
A *Single Common Substation* is a substation where:
  i. each substation that is connected by an Offshore Interlink is connected via at least one circuit without passing through another substation; and
  ii. all routes connecting each substation that is connected by an Offshore Interlink to the MITS pass through.

14.15.65 The proportion of the OFTO revenue associated with the Offshore Interlink allocated to each generator benefiting from the installation of an Offshore Interlink must be agreed between these Users:
  a. All relevant Users must notify The Company of its respective proportions three months prior the OTSDUW asset transfer in the case of a generator build, or the charging date of the first generator, in the case of an OFTO build.
  b. All relevant Users may agree to vary the proportions notified under (a) by each writing to The Company three months prior to the charges being set for a given charging year.
  c. Once a set of proportions of the OFTO revenue associated with the Offshore Interlink has been provided to The Company, these will apply for the next and future charging years unless and until The Company is informed otherwise in accordance with (b) by all the relevant Users.
  d. If the Users are unable to reach an agreement on the proportioning of the OFTO revenue associated with the Offshore Interlink they can raise a dispute. Any dispute between two or more Users as to the proportioning of such interlink revenue shall be managed in accordance with CUSC Section 7 Paragraph 7.4.1 but the reference to the 'Electricity Arbitration Association' shall instead be to the 'Authority' and the Authority's determination of such dispute shall, without prejudice to apply for judicial review of any determination, be final and binding on the Users.

The Locational Onshore Security Factor

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

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

14.15.68 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 and fixed for the duration.

Local Security Factors

14.15.69 Local onshore security factors are generator specific and are applied to a generators local onshore circuits. 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 redundancy, a local security factor is applied that is equal to the locational security factor, currently 1.8.

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

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

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

14.15.71 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, derived as 1.8 for 2010/11.

14.15.72 The offshore local security factor for configurations with one or more Offshore Interlinks is updated so that the offshore circuit tariff will include the proportion of revenue associated with the Offshore Interlink(s). The

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

specific offshore local security factor for configurations involving an Offshore Interlink, which may be greater than 1.8, will be calculated for each offshore connection using the following methodology:

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

Where:

IRevOFTO = The appropriate proportion of the Offshore Interlink(s) revenue in £ associated with the offshore connection calculated in 14.15.64

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

$LocalSF_{initial}$ = Initial Local Security Factor calculated in 14.15.70 and 14.15.71 And other definitions as in 14.15.70.

The remaining paragraphs in Section 14.15 (originally 14.15.70 to 14.15.103) are to be renumbered to 14.52.73 to 14.15.106.