nationalgrid

Stage 04: Code Administrator Consultation

- Volume 3

Connection and Use of System Code (CUSC)

CMP213 Project TransmiT TNUoS Developments

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

Consultation Responses

Published on: 10th April 2013

Contents

About this document

This document contains the responses to the Workgroup Consultation which took place between 07 December 2012 and 15 January 2013.

Document Control

Version	Date	Author	Change Reference
1.0	10 April 2013	Code Administrator	Publication to Industry

Any Questions?

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1. Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	*Marc Murray* *e-mail: marc.murray@aquamarinepower.com* *phone: 0131 524 1431*
Company Name:	*Aquamarine Power*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	*Aquamarine Power is the technology developer of the Oyster Wave Power technology, which captures energy from near shore waves and converts it into clean sustainable electricity. A Scottish company, based in Edinburgh, we were established in 2005 with a clear mission; to make marine renewable energy mainstream through rapid and responsible commercialisation of the Oyster wave energy converter technology.* *Aquamarine Power has secured to date, through its associated development company Lewis Wave Power and its Brough Head Wave Farm Ltd development partner SSE Renewables, grid capacity of over 240MW for a number of projects based on the Scottish Islands. In common with the majority of planned projects (>95%) in the nascent wave industry, cost competitive and viable island connections are intrinsic to establishing the long term potential of this emergent new source of reliable renewable energy.* *We believe that the CMP 213 objectives of competition, cost reflectivity and reflecting transmission developments has been too narrowly interpreted by the working group and fails to*

	address some of the key challenges facing the emergent wave industry and more generally the Scottish Islands; specifically: • *The narrow interpretation of competition fails to take into account how the actions proposed by the workgroup in both the original and amended versions will impact competition between various forms of electrical generation technologies. Both the original and amended proposals create an artificially high barrier to entry to the UK energy market for wave technologies. Fundamentally the proposals are handing an unfair competitive advantage to other generation technologies which are not locational dependent.* • *Cost reflectivity has been too loosely applied when considering island technologies to "normal" onshore connections, with island connections facing localised charges that would not be charged for an onshore connection. Again artificially raising the barrier to entry for island developments, including wave technologies. There need to be comparable treatment with wider assets. At the very minimum we agree with the suggestion that HVDC connection costs should be treated in the same manner as AC connections (i.e. removal of the HVDC elements that are not included in the locational signal for an AC transmission network)* • *In terms of reflecting transmission developments, the Scottish Islands have been categorised or treated the same as an offshore wind development (as they both need HVDC connections). We believe that this is unwarranted and that the charging arrangements for the Scottish Islands should be considered separately to the offshore connections. The Scottish Islands need to be treated as the exception to the rule, taking into account their special circumstances. The islands should be treated as a strategic asset that requires a connection solution that encourages renewable connections on the islands, rather than creating a barrier to development. The distinct message is that the CMP 213 has failed to find a solution to the Scottish Island connection issue; instead the proposals more generally raise the barrier to achieving a sustainable solution to connecting the islands.* • *Finally we believe that other fundamental considerations should have been taken into account, such as security of supply and sustainability, which, although key criteria for both National Grid and Ofgem, have been given much less weighting than the heavy focus on locational cost reflectivity. A long term cost effective solution needs to be identified for the islands (without reliance on temporary support*

	mechanisms such as ROCs or capping), which the workgroup has failed to address.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*As stated before we believe that both proposals are inadequate to address the Scottish Islands solution; specifically:* *(a) Both methodologies present an artificial barrier to wave technologies to effectively compete within the UK generation market, with the resultant effect of reducing the UK's security of supply.* *(b) The locational element in both charging methodologies has effectively "double accounted" transmission assets for island connections – effectively over charging on locational elements – we disagree with the over emphasis on locational charging and specifically seek more elements of the islands connections to be socialised (recognising it as a national asset, rather than a company asset which an offshore connection would be)*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	*For the Scottish Islands elements, we do not support either approach. Instead a more fundamental solution to the Scottish Islands connections needs to be implemented, including the consideration of socialising the HVDC connection as part of the wider UK asset infrastructure (i.e. being the exception to the rule that treat connections beyond the nearest MITS station as local works)*

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	*No, we believe that the scope of the review was too narrowly interpreted by the workgroup. In essence all that was considered was how Scottish renewable and English base loads interacted, failing to address/ investigate the impact of diversity of generation types. The amended version effectively heightens the barrier to Scottish Island connections.* *In addition the ability of different generation technologies being able to share the same transmission infrastructure (e.g. wave and wind) based on the intermittency of the generation characteristics needs to be considered (particularly on the local island networks).*

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*As question 1*
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	*No, we believe that:* • *Further consideration is required on the sharing between different generation types (e.g. counter correlation between wave and wind) as suggested by ICIT.* • *More detailed consideration of terming the Islands as MITS for charging purposes to present a more cost effective solution.* • *Consideration of socialising the HVDC connection as part of the wider UK asset infrastructure (i.e. being the exception to the rule that treat connections beyond the nearest MITS station as local works)*

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	• *Whilst it is accepted that the investment cost would be higher, the outcome should not be that TNUoS charges for the island are 10 times their nearest neighbours (as in the case of Lewis and Skye). We believe that an alternative focus for island connection is required, rather than a one size fits all methodology. The most sustainable solution would be to make the island connections as the exception to the rule, rather than being reliant on external temporary imposed solution (such as additional island ROCs or capping).*
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	*We disagree with the suggestion that the Scottish Islands should be treated the same as an offshore wind development (as they both need HVDC connections). The charging arrangements for the Scottish Islands should be considered separately to the offshore connections. The Scottish Islands need to be treated as the exception to the rule, taking into account their special circumstances. The islands should be treated as a strategic asset that requires a connection solution that encourages renewable connections.* *At the very minimum we agree that Island HVDC connection costs should be treated in the same manner as AC connections (i.e. removal of the HVDC elements that are not included in the locational signal for an AC transmission network)*
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	*Fundamentally we believe that the either changing the charging definition of Local and Wider, or treating the connections to the Scottish Islands as MITS for charging purposes. This is the only way to ensure that this UK strategic asset is realised. Arguments such as security of supply and sustainability alone make this a reasonable suggestion.*

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*A stated before further work is needed on the capacity for sharing amongst intermittent generation technologies and counter correlation (in line with the ICIT work)* *We would also ask that the workgroup look at a wider definition of the narrow interpretation of the remit to ensure that other factors beyond locational charging is examined; to ensure that the full benefit on the basis of competition, security of supply and sustainability is achieved.*
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	• *Fundamentally the review has failed to achieve clarity on island charging or provide a long term sustainable solution to connecting the generation capacity of the Scottish Island renewable resource; in particular the vast majority of the available UK wave resource.* • *The outcome of the TNUoS review should not significantly disadvantage the islands to any other part of the UK mainland. Whilst it is accepted that the investment cost would be higher, the TNUoS charges for the island should not be 10 times their nearest neighbours (as in the case of Lewis and Skye). A sensible outcome needs to be achieved. This has to be the focus for island connections, rather than focussing on one size fits all methodology. It needs to be accepted that the only sustainable solution is to make the island connections as the exception to the rule, rather than being reliant on external temporary imposed solution (such as additional island ROCs or capping).* • *At a very minimum, where island conform to the definition of Wider, they should be treated in the same way as any other part of the onshore network.* • *Island links , where they are radial HVDC should be as a minimum be treated in the same way as parallel "bootstrap" links as far as expansion factors are calculated* • *A security factor of 1 (whether is it's classified as wider or local) should be used for links where there is no redundancy.*

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	*We believe that clarity is very important for the industry. We suggest that finalisation of the general arrangements are as soon as possible; however ensuring that the door is left open to find a systemic solution for island connections that does not significantly disadvantage the islands to any other part of the UK mainland.*
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	-
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	
Do you have any other comments?		

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	Ricky Hill (ricky.hill@centrica.com)
Company Name:	Centrica
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Centrica welcomes this consultation and the work undertaken by the working group to develop the CMP213 proposals. Nevertheless, we believe that there would have been merit in publishing the consultation at a later date when the potential alternatives on sharing have been further developed to a level where parties are better able to assess the impact on charges. On the back of this Users (especially non–workgroup parties) would be more able to comment on the direction and suitability of alternatives. We believe that a key issue is the compressed timescales of the CUSC process. Indeed, it seems that timescales are the key driver of this process and that there is a risk that the group will arrive at a sub-optimal conclusion and / or that group will not have sufficient time to fully work up the alternatives for the code administration consultation. This would evidently be a sub-optimal outcome and could delay the process further. In the light of this we ask that workgroup review the current work plan and request an extension on the timescales if required. We also believe that it would be helpful to get feedback from Ofgem on whether they have any concerns or foresee any issues with the work being undertaken by the group.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	**No**. In particular, we believe that the original would not better achieve CUSC objectives a) and b): the effective competition in the generation and supply of electricity and the production of charges which reflect, as far as is reasonably practicable, the costs incurred by transmission licensees. The proposed original would lead significant financial transfers between parties without robust justification. We believe that the

	analysis developed through the Working Group, Centrica and work we commissioned from Bath University[1] has demonstrated that many of the key arguments of the proposals are flawed. The CMP213 original is founded on the proposer's conclusion (using analysis from the ELSI model) that a generator's annual load factor shows a high degree of linearity with incremental constraint costs, accepting that this relationship breakdown over time. The evidence which is used to demonstrate this linearity is typically based on a 2011/12 generation background (inc. that on pages 176 to 179 of the workgroup consultation document). Analysis undertaken by Centrica using the ELSI model using 2015/16 input data (including boundary capacity data from the Seven Year Statement) show no distinguishable linearity between load factor and constraint costs in the majority of zones (please see the annex). Examining the relationship between load factor and incremental constraint costs the ELSI model produces on a 2015/16 background is important because it is, for obvious reasons, a more relevant time period than 2011/12. The breakdown of any perceivable relationship by 2015 should be examined by the Working Group. We have sought to further research whether load factor is a key driver of incremental constraint costs and whether the original could result in cost reflective charges. The study we commissioned from Bath University demonstrates that the relationship between congestion cost and load factor is far from linear and that congestion costs depend on network location, the network characteristics, the characteristics of the generation and the profile of demand. The Redpoint modelling undertaken in 2011 demonstrated that the Improved ICRP original would have £1.4 billion predicted impact on consumers' bills to 2030 relative to the status quo whilst at the same time providing minimal benefit to the deployment of renewables. These increases in costs to consumers seem incongruent with the current environment of consumers being financially squeezed and subsequent regulatory measures being taken to reduce costs. It also sits ill at ease with Ofgem's first priority which is protecting existing and future customers. We do not believe that the original properly takes account of the developments in transmission licensees' transmission businesses, and in particular the way in which it interprets the "dual criteria" changes to the SQSS as a "dual background" in charging. For example, CMP213 uses peak demand to bin both 'peak' and 'year-round' which does not seem appropriate with respect to the calculation of the latter tariff. The 'year-round' tariffs is supposed to reflect the second criterion in the GSR009 changes which introduce an economy criterion that requires that

[1] We commissioned the University of Bath to examine the drivers of year-round system congestion costs in the light of CMP213. We intend to circulate the report to the group shortly.

	sufficient transmission system capacity be provided to accommodate all types of generation in order to meet varying levels of demand efficiently. In summary, we do not believe that the dual tariff results in an incremental signal that is meaningful or accurately replicates the aims of the SQSS changes undertaken through GSR009.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Whilst we do not support CMP213 as it stands, option 4 (April 2015) is in our view the most appropriate date for implementation. The technical feasibility of an April 2014 implementation is wholly dependent on strict deadlines being met. In addition, assuming April 2014 is technically possible, it does not provide generators with sufficient foresight to react to the change in signal. This could partially be overcome by reducing the required notice period to amend TEC levels, but it would not provide sufficient notice to generators to deal with other issues including site closures with associated redundancies and the unwinding of power purchase contracts.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	We believe that the Workgroup has adequately set out and considered all relevant options, subject to a slight alternation to method 3. We believe that the analysis undertaken by the working group shows that the proposed linearity between load factor and constraint costs within the Original is found wanting particularly in areas dominated by one type of generation. Given that the network will increasingly have areas dominated by one generation type, which will further reduce the proposed linear relationship between load factor and constraint costs, we believe that in order for any new charging methodology to be credible and future-proof, it is essential that an alterative be developed that takes diversity of generation into account. Of the three potential alternatives to sharing outlined on page 52 of the consultation, our current view is that method 3, subject to a small amendment described below, has the most potential to overcome the inadequacies of the Original. This is because as well as taking into account of generation diversity, it would also be calculated on a single background. As noted above, Centrica does not believe that splitting the TNUoS tariff into peak and year-round will result in an incremental signal that is meaningful as it distorts the aims of the NETSQSS changes to which it is associated. We propose amending method 3 such that the assumed level

Q	Question	Response
		of sharing is not capped at an arbitrary 50% (currently, of the proposed alternatives, only method 1 does not arbitrarily cap the level of sharing at 50%). Capping the amount of deemed sharing at a maximum 50% based on the fact that "maximum sharing occurs when a TNUoS zone contains an equal capacity of both low carbon and carbon generation and that the optimum transmission boundary capacity would be 50% of the combined capacities" is flawed. We can assume a case where two 100MW generators (G1 ad G2) are sharing a 100MW transmission asset. G1 is running at full capacity and G2 is turned off and they then swap, such that G1 is turned off and G2 is running at full capacity. It is evident that 100% sharing has taken place. In summary, we believe that a method 3 which is modified in this way is likely to lead to more cost-reflective and justifiable changes to Users' tariffs than that proposed in the Original. We would ask the working group to vote on taking this forward as an alternative and note our recent informal conversation with National Grid outlining out intention to propose this in this manner.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	We think that the options on how a sharing factor (i.e. ALF) could be calculated have been sufficiently reviewed. However, with regards to the option whereby ALF would be calculated on a 5-year historic basis, we would ask the Working Group to review the case to reduce this to 3 years. Whilst we accept that analysis described in Annex 9 which shows little difference between an ALF based on 3 years previous data or 5 years previous data, we believe that given the significant changes occurring on the system, in particular with gas plant being out of merit and entering into STOR contracts, a 3 year historic ALF could be much more represented of future load factor.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	We do not have a strong view whether intermittent generation should be exposed to the peak element of the TNUoS tariff. This is because we fundamentally disagree that the methodology for deriving the peak tariff either accurately replicates the objectives of the SQSS GSR009 change or provides a meaningful signal.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We believe all the high-level potential options for sharing which are relevant to this modification proposal have been considered. This is subject to our response to question 1 where we stated that we propose amending method 3 such that the assumed level of sharing is not capped at an arbitrary 50%. We do, however, believe that that potential alternatives should have been more adequately set out in terms of explaining their likely impact on tariffs relative to the Original. We believe that there would have been merit in publishing the consultation at a later date when the alternatives on sharing have been further developed, in particular with regards to the associated impact on charges. This would enable parties (especially non – workgroup parties) to better comment on the direction and suitability of alternatives.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	Our current initial view is that in the in the absence of a model with multiple backgrounds, which is unlikely to be practical in the context of CMP213, the current ICRP methodology calculated on a single background would seem to best reflect the differential impact of generators on incremental network costs. Nevertheless, we encourage the development of alternatives which build on the CMP213 original to take into account generator diversity as well as load factor and will judge these on their own merit. We do not believe that CMP213 original would be an accurate reflection of generators' impact on incremental network costs. As the workgroup has discussed, and Bath University work has demonstrated, while load factor is a measure of an average output of a generation technology over the year, the cost of congestion varies between locations and changes in its intensity, time, and duration throughout the year which is not represented in CMP213 original. Rather, the use of a single year-round scenario and load factor to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout of the year which has been proven to not be the case. In theory, a more cost reflective TNUoS charge would relate the charges with times and boundaries when congestions are most severe by introducing a time of use element to the existing peak security based TNUoS charges. This would expand the present year-round scenario to a number of scenarios that are directly linked to congestion times and boundaries. This would essentially equate to a market model. However, as the TAR process has shown, it is extremely difficult for generators to provide the requisite information to make this viable, at least on an ex-ante basis.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, at the current time we believe that all relevant options have been considered.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Centrica believes that HVDC circuits should be incorporated into charging methodology in a way which most accurately reflects the associated costs and is consistent with the rest of the charging methodology. In this respect we believe that 100% of the cost of the sub-sea cables should be included in the expansion factor. However, with regard to the converter stations, we believe that there may be merit in removing those elements that are similar to the AC transmission network. Should such an approach be implemented we believe that it should also be replicated in the methodology for offshore links. In terms of calculating the flows on HVDC links we note that the calculation of impedance is not an exact science due to its controllable nature and that a reasonable proxy needs to be developed. We currently support the methodology set out in the original proposal which would calculate the base case flow down the HVDC transmission circuit as a ratio of power flows to circuit ratings across a transmission network boundary ‘crossed’ by the HVDC circuit. We believe this to be a pragmatic approach to a calculation that is ultimately subjective. We note that the Working Group discussed a potential alternative which would calculate the base case flows on the single most constrained transmission boundary that the HVDC circuit reinforces. However, we did not entirely understand the justification for this approach and would welcome further clarity in this area.

Q	Question	Response
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, at the current time we believe that all relevant options have been considered.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes, at the current time we believe that all relevant options have been considered.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, at the current time we believe that all relevant options have been considered.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	At the current time we believe that the principles set out in the Original generally offer the best. This is of course subject to our serious concerns about the sharing proposals that we outline in our response to questions 1 to 5. In line with the original, we do not believe that there in a requirement to change the definition of a MITS node. Furthermore, as the workgroup has noted, and because of zoning and the specific expansion the island generation tariff for an island link classed as local or wider is likely to be very similar. As a supporter of cost reflectivity in transmission charges, we believe the approach set out in the Original whereby new expansion factors would be calculated for each type of transmission technology and the locational security factor would be adjusted to reflect redundancy provided on the link offers the best solution at the current time. In terms of the different expansion factors to be calculated for each type of technology, we would support this being undertaken on to a high level of granularity such that the principle of cost reflectivity is followed as robustly as possible. In line with our response to question 9, we believe that with regard to converter stations for HVDC island links, there may be merit in removing from the expansion factor those elements that are similar to elements of the AC transmission network HVDC.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	Whilst we do not support CMP213 as it stands, option 4 (April 2015) is the most appropriate date for implementation. The technical feasibility of an April 2014 implementation is wholly dependent on strict deadlines being met. In addition, assuming April 2014 is technically possible, it does not provide generators with sufficient foresight to react to the change in signal. This could partially be overcome by reducing the usual required notice period to amend TEC levels, but it would not provide sufficient notice to generators to deal with other issues including site closures with associated redundancies and the unwinding of power purchase contracts.

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Please see response to question 16.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	Yes, please see response to question 1
Do you have any other comments?		We commissioned the University of Bath to examine the drivers of year-round system congestion costs in the light of CMP213. We intend to circulate the report to the group shortly.

Annex - the linearity of the relationship between load factor and incremental constraint costs

Introduction

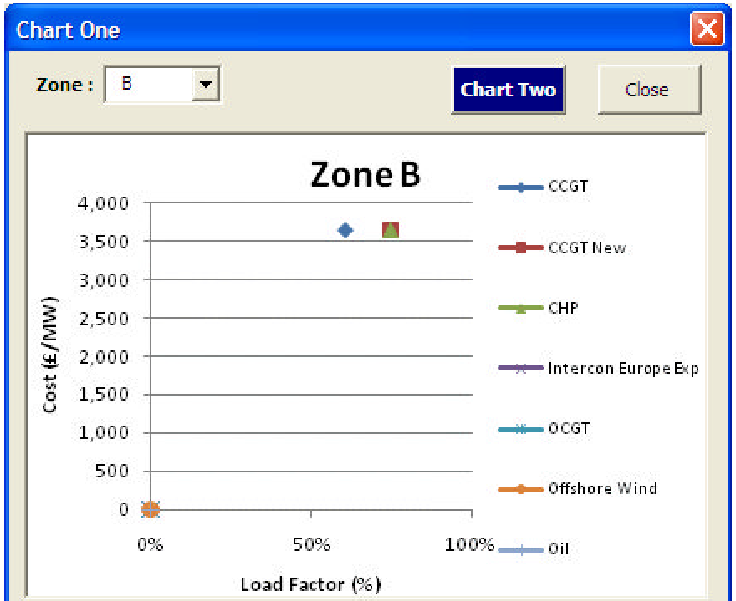
- The purpose of these slides is to illustrate some of the work done using the ELSI model to view how the linearity between load factor and incremental constraint costs changes over time. Each of the zones was modelled for both 2011/12 and 2015/16 but for the purposes of this annex we have just included a selection for illustrative purposes. We are happy to present all of the analysis to the work group.

- For the analysis we used ELSI version 4 circulated on 28th August 2012. We have used a gone green generator scenario, scaling and prices. We have used the 2011 National Grid Seven year Statement to input 2015/16 boundary capacities.

- Based on the above assumptions, in most zones, there is no perceivable linearity between incremental constraint costs and load factor by 2015/16. This also true of zone Z (northern Scotland) which sees the amount of wind generation increase from 850MW to 2010MW over the period. In zone R, where a strong level of linearity is maintained , there is a relatively high level of generation diversity.

Zone B

2011/12



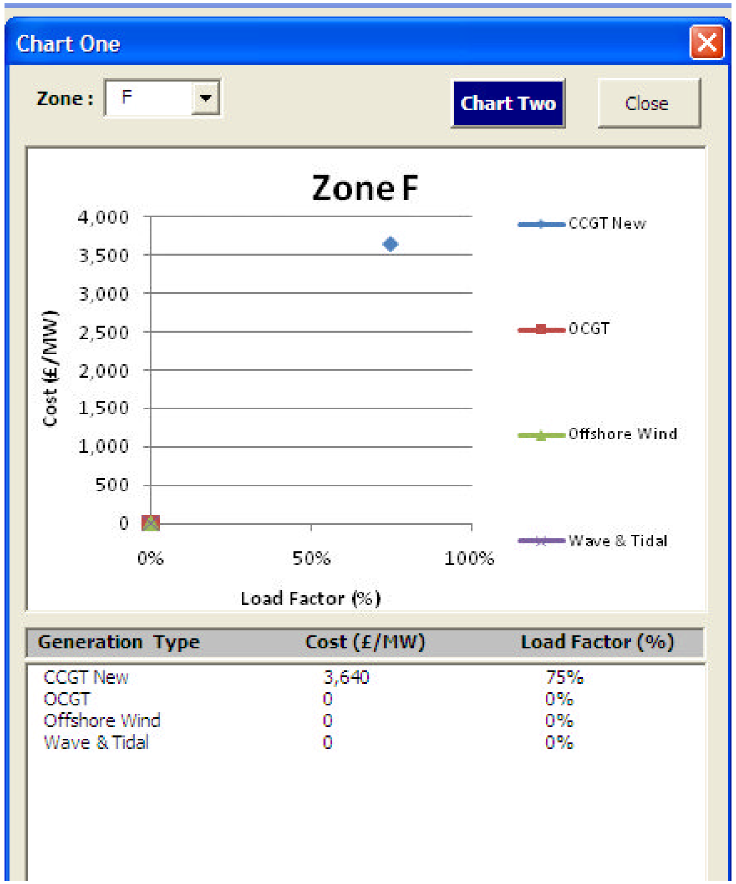
Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	3,640	61%
CCGT New	3,640	75%
CHP	3,640	75%
Intercon Europe Exp	0	0%
OCGT	0	0%
Offshore Wind	0	0%
Oil	0	0%

2015/16

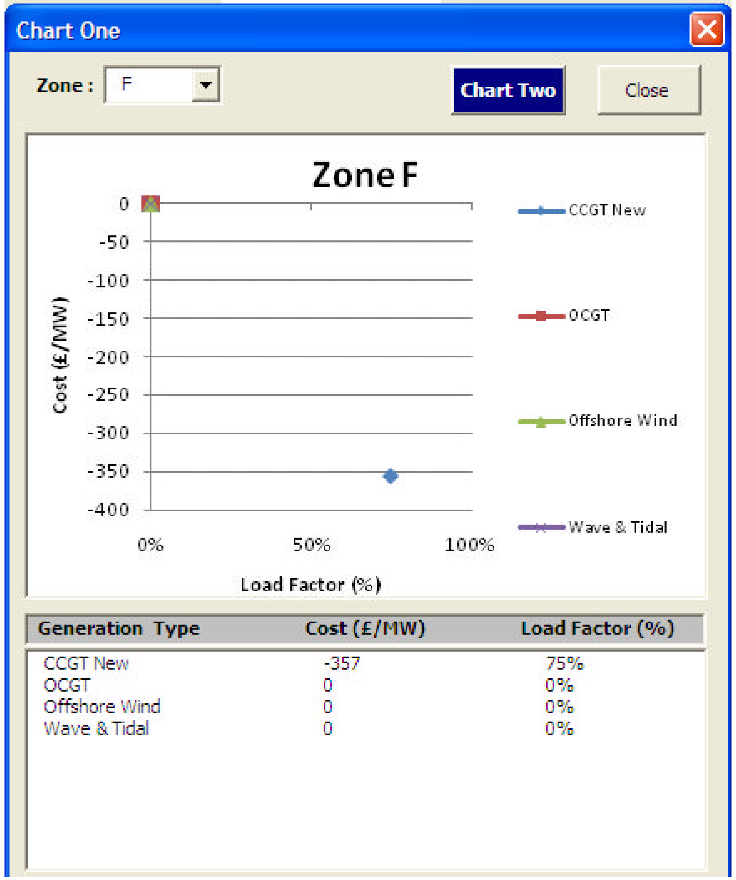
Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	-357	46%
CCGT New	-357	75%
CHP	-357	75%
Intercon Europe Exp	0	0%
OCGT	0	0%
Offshore Wind	0	0%
Oil	0	0%

Zone F

2011/12

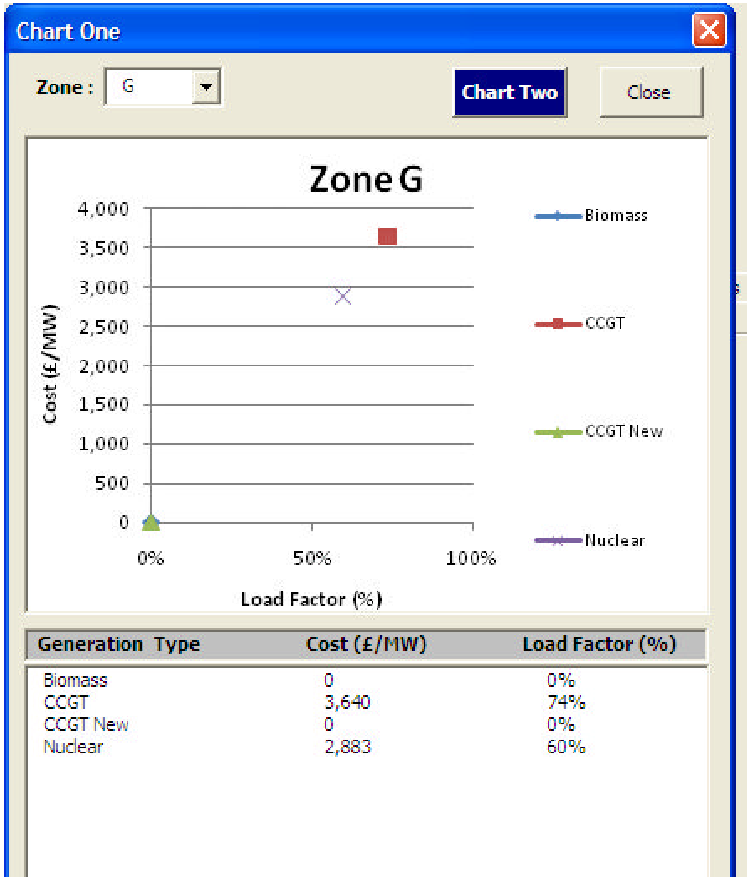


2015/16



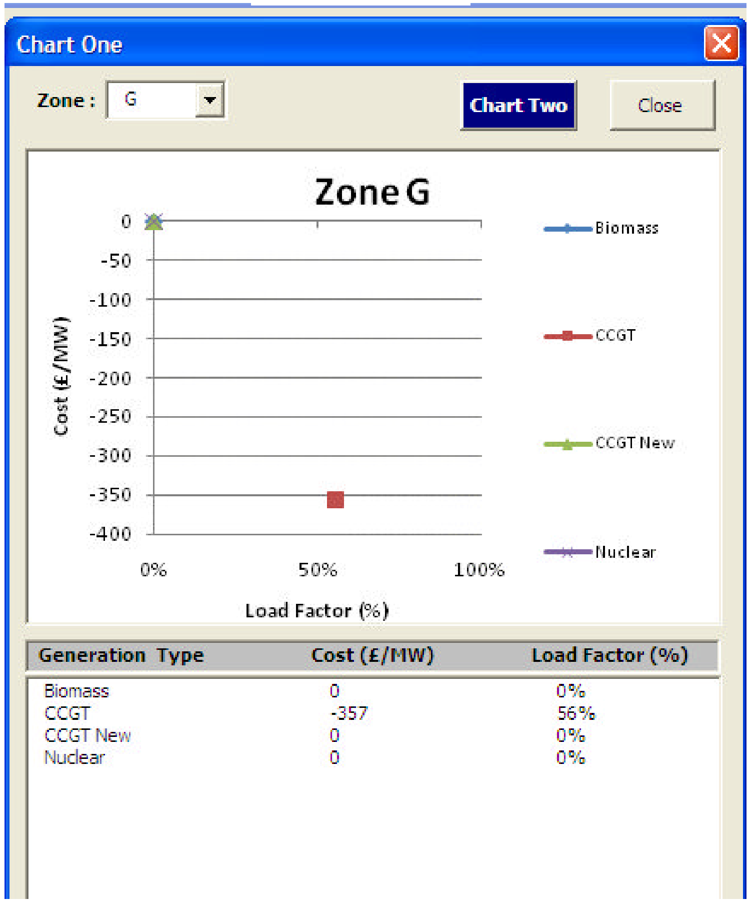
Zone G

2011/12



Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	0	0%
CCGT	3,640	74%
CCGT New	0	0%
Nuclear	2,883	60%

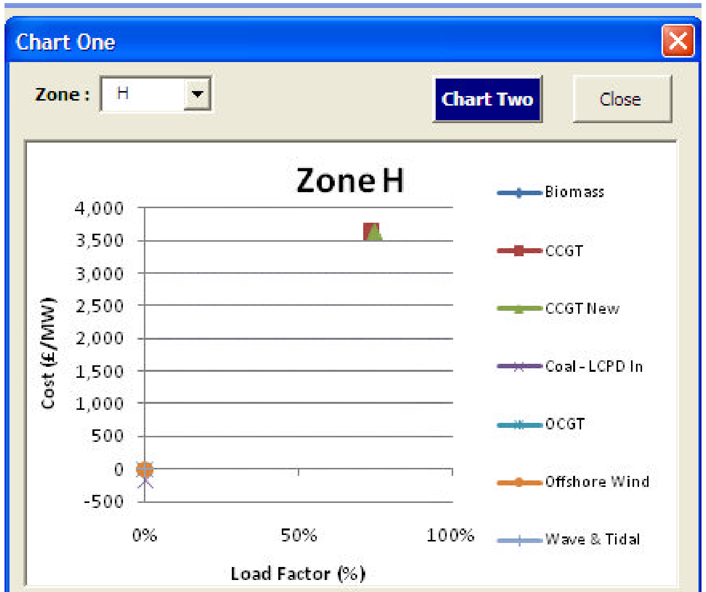
2015/16



Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	0	0%
CCGT	-357	56%
CCGT New	0	0%
Nuclear	0	0%

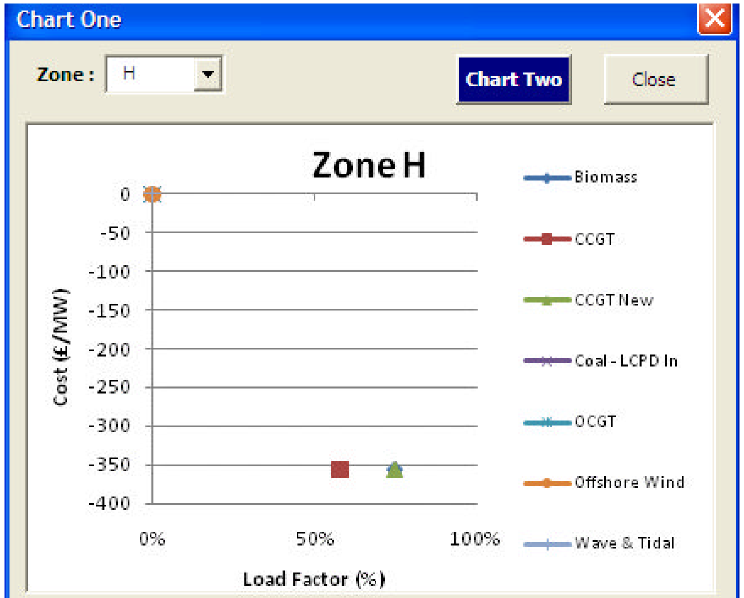
Zone H

2011/12



Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	0	0%
CCGT	3,640	74%
CCGT New	3,640	75%
Coal - LCPD In	-163	1%
OCGT	0	0%
Offshore Wind	0	0%
Wave & Tidal	0	0%

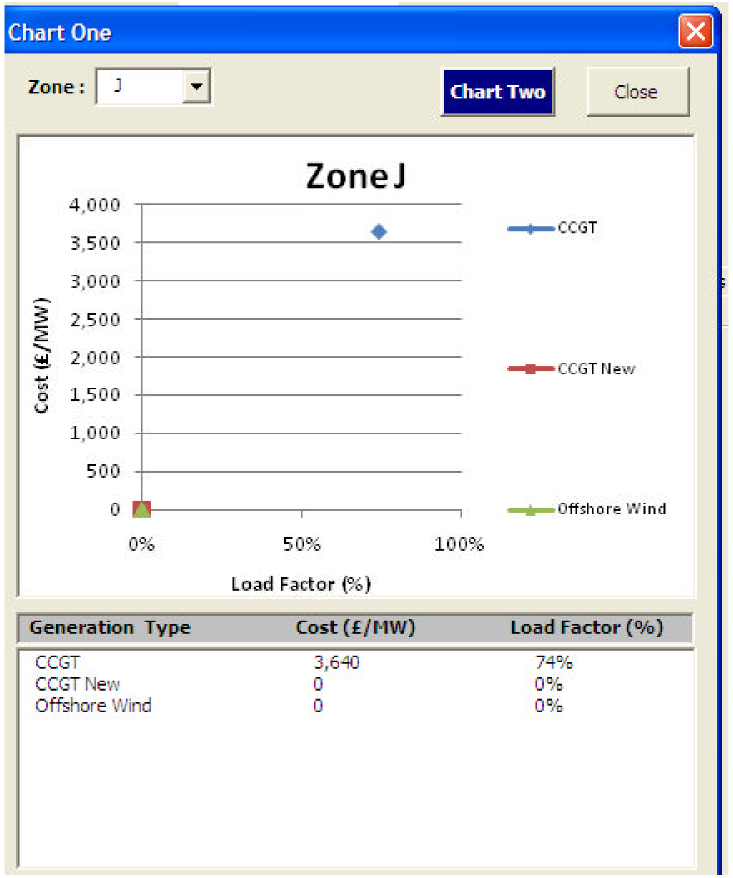
2015/16



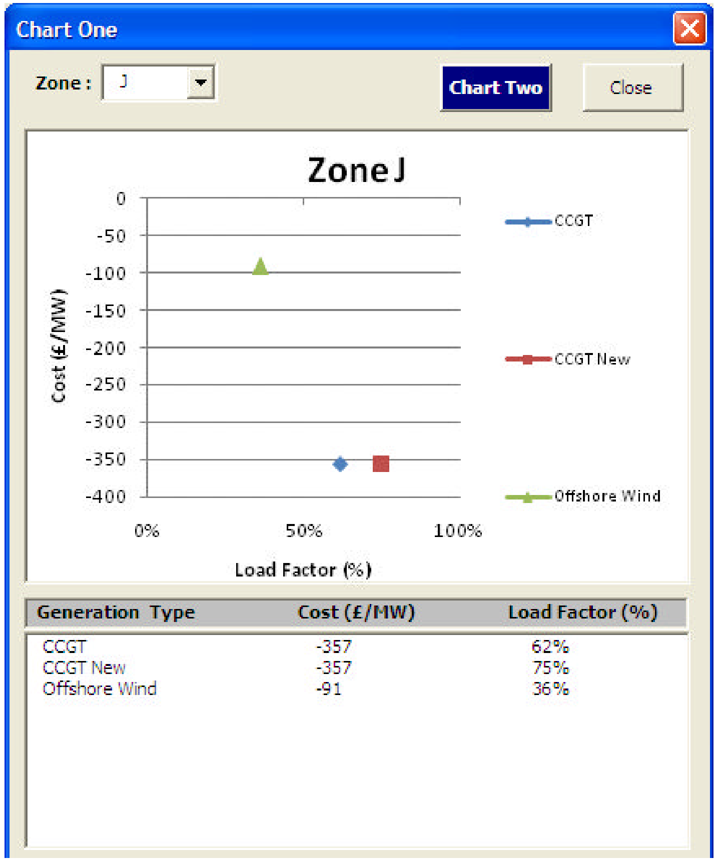
Generation Type	Cost (£/MW)	Load Factor (%)
Biomass	-357	75%
CCGT	-357	58%
CCGT New	-357	75%
Coal - LCPD In	0	0%
OCGT	0	0%
Offshore Wind	0	0%
Wave & Tidal	0	0%

Zone J

2011/12



2015/16

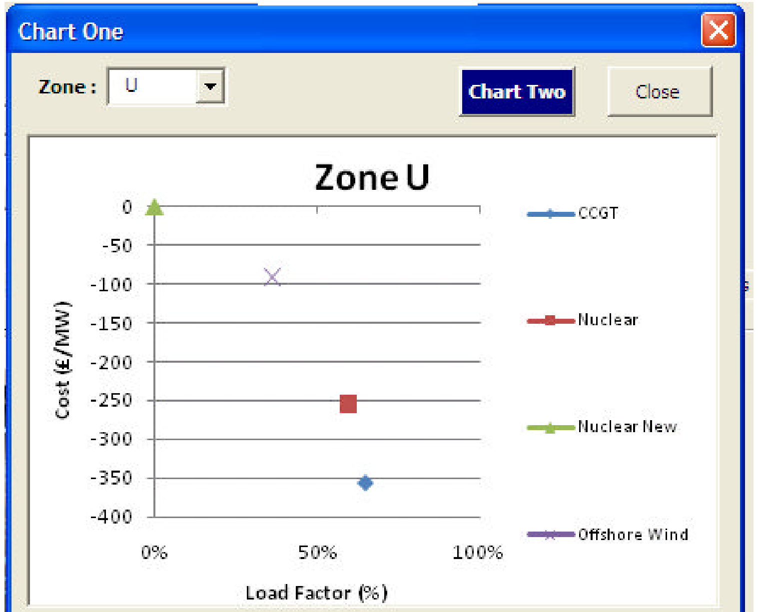


Zone U

2011/12

Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	3,640	75%
Nuclear	2,883	60%
Nuclear New	0	0%
Offshore Wind	4,944	33%

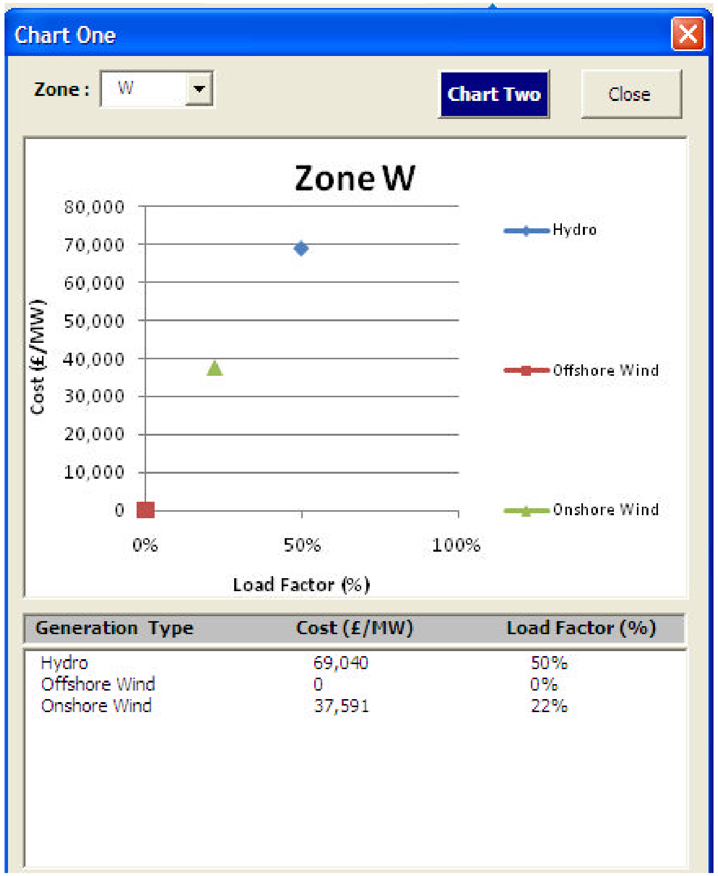
2015/16



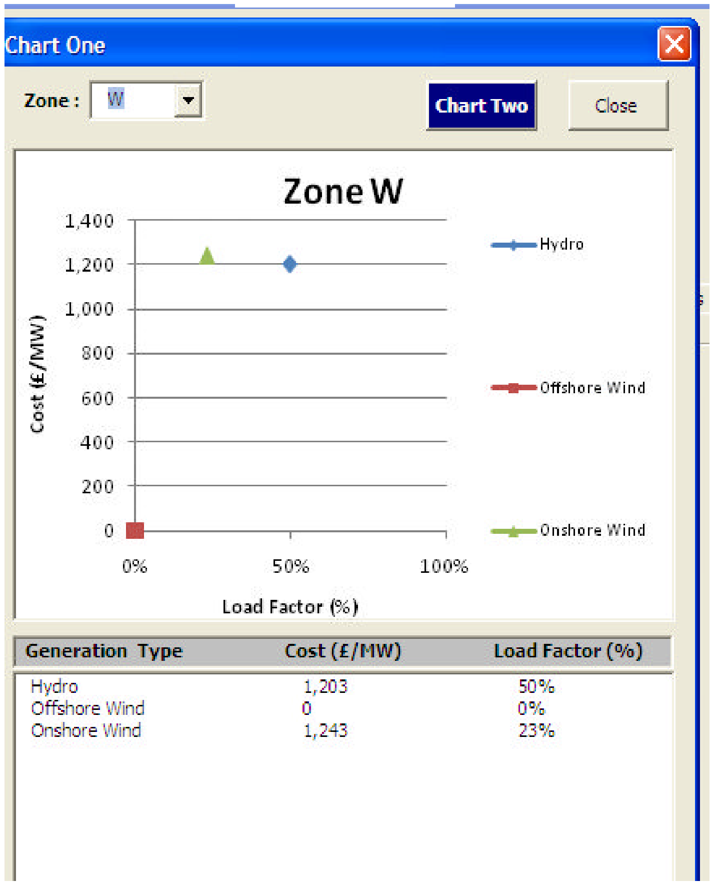
Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	-357	65%
Nuclear	-255	60%
Nuclear New	0	0%
Offshore Wind	-91	36%

Zone W

2011/12

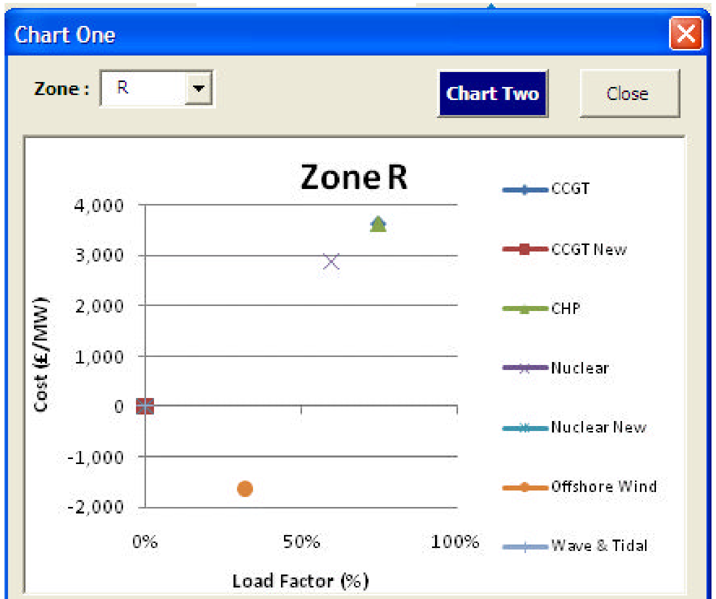


2015/16



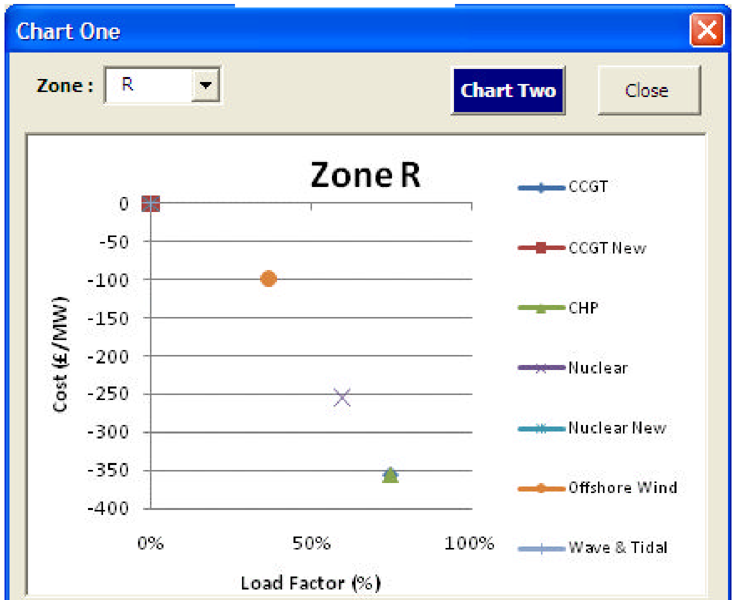
Zone R

2011/12



Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	3,640	75%
CCGT New	0	0%
CHP	3,640	75%
Nuclear	2,883	60%
Nuclear New	0	0%
Offshore Wind	-1,638	32%
Wave & Tidal	0	0%

2015/16



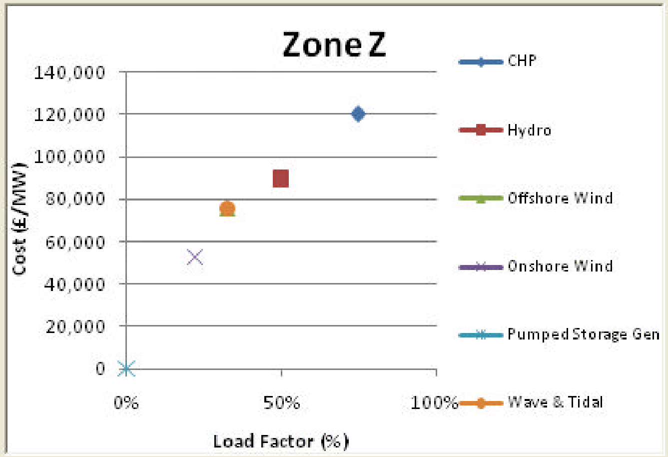
Generation Type	Cost (£/MW)	Load Factor (%)
CCGT	-357	75%
CCGT New	0	0%
CHP	-357	75%
Nuclear	-255	60%
Nuclear New	0	0%
Offshore Wind	-99	37%
Wave & Tidal	0	0%

Zone Z

2011/12

Chart One

Zone : Z — Chart Two — Close

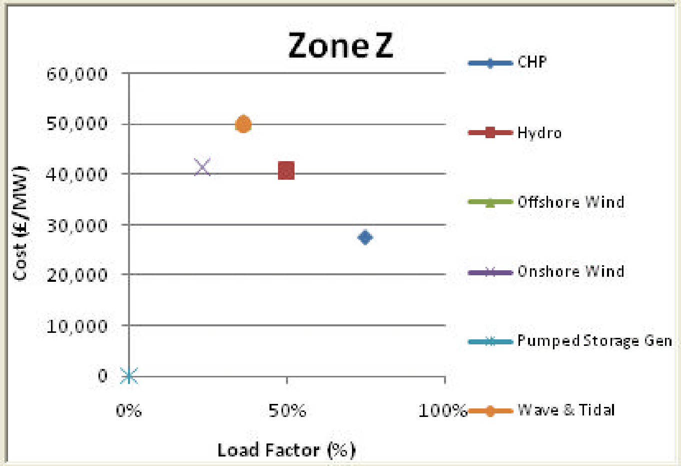


Generation Type	Cost (£/MW)	Load Factor (%)
CHP	120,364	75%
Hydro	89,708	50%
Offshore Wind	75,906	33%
Onshore Wind	52,510	22%
Pumped Storage Gen	0	0%
Wave & Tidal	75,906	33%

2015/16

Chart One

Zone : Z — Chart Two — Close



Generation Type	Cost (£/MW)	Load Factor (%)
CHP	27,514	75%
Hydro	40,798	50%
Offshore Wind	50,325	36%
Onshore Wind	41,448	23%
Pumped Storage Gen	0	0%
Wave & Tidal	49,914	36%

DONG energy

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RE: CMP213 Project TransmiT TNUoS Developments

15 January 2013

Our ref. 130115_CMP213

Danielle Lane
dlane@dongenergy.co.uk
Tel 02078115200

Thank you for the opportunity to comment on the work carried out by the CMP213 working group. DONG Energy is a leading energy company operating in Northern Europe and headquartered in Denmark. It is one of the most active offshore wind operators and investors in the United Kingdom. We operate 700 MW of offshore wind farms, and have approximately 1.2 GW under construction and a strong pipeline of future projects. In addition to our offshore wind farms, we own and operate a 824 MW CCGT plant in Wales.

The working group has done a good job in carrying out a comprehensive review, and we do not believe that further issues should be considered at this time. Subject to the commercial consequences of the original proposal, we believe this is broadly the right option for the working group to look at.

Sharing

We believe the core principles have been addressed for the sharing issue, and support the link between the SQSS planning statement and the proposed changes to TNUoS charges. We further believe there is merit in investigating the diversity issue further, but within the scope already set out by the report. We recognise that there is a potential conflict between the cost reflectivity and simplicity and transparency of the potential sharing with diversity options, but do not believe that the options as presented in the work group report have been developed to a sufficient stage for us to comment on in more detail.

However, as TNUoS charges have large commercial implications for generators, we further believe stakeholders should be given sight of the possible changes to tariffs and be given an opportunity to comment further on the proposals with this information in mind.

HVDC Circuits

We remain uncertain as to why the original proposal has chosen to treat HVDC circuits as a pseudo-AC technology in one instance, and as a technology

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completely separate from AC in another: the proposal to on the one hand model the load flow component as AC, but treat the expansion factor as DC is not consistent. While incorporating a new technology into the models used by National Grid is not simple, we believe it has to be done in a consistent manner.

We are thus uneasy as to the treatment of HVDC, on one hand, as a pseudo AC circuit in determining flows on the system, but as a HVDC link with no socialisation of costs when calculating expansion factors on the other. HVAC substation equipment is not locationally charged, and we would be interested to see what proportion of the regulated asset base is made up of these types of assets. The HVDC solution for west coast reinforcement was chosen not only based upon the ability to deliver the necessary reinforcement in a timely manner, but also on a cost benefit when considering CAPEX and OPEX (system losses) against a 400kV onshore solution. If a solution represents the cheapest option for reinforcing the system, we do not believe it should it be charged at a premium.

The option of including the converter stations in the circuit expansion factor would result in a negative impact on competition: for a similar capital cost as an AC link (although we recognise that in the case of the bootstraps onshore AC reinforcement is deemed not possible in the timescales required), the DC link would result in significantly higher TNUoS charges for some generators. It does not seem reasonable that certain generators should be negatively impacted based on the technology choice of the TO, when the CAPEX costs are so similar.

It may be possible to calculate an expansion factor for a HVDC investment by multiplying the overall HVDC CAPEX by the ratio of line to substation assets in the remainder of the onshore RAV, thus giving the 'HVDC premium' relative to the average level of socialisation onshore (if indeed there is one). This cost can then be divided by the distance, and MW rating of the circuit giving a MWkm figure which can be used in calculation of the expansion factor relative to a 400kV overhead line. Thus giving a proportional expansion factor, normalised to the degree of socialised assets in other parts of the network.

Further, we have a few comments on specific paragraphs in the consultation document:

- 5.24: £550m does not seem like an accurate estimate of HVDC converter costs. We believe it should be closer to £300m as the cable manufacturer Prysmian claim to have received ~800m Euros, against a total pot of ~1.1bn Euros for the Western link[1].

[1] http://investoren.prysmian.com/phoenix.zhtml?c=211070&p=irol-newsCorporateArticle_pf&ID=1661739&highlight=

- 5.26: HVDC converter stations are necessary to HVDC systems in the same way that HVAC substations are necessary to HVAC transmission. There is a difference in that the HVDC terminal equipment is generally higher as a proportion, than the HVAC equivalent – with AC circuit costs being higher.

- 5.61 – 5.63: Do the overhead costs include maintenance costs for substation assets? Or just the line elements? A very significant proportion of the maintenance costs on the network is tied up in substation equipment & auxiliaries, protection, control etc. We do however agree with keeping a constant expansion factor for simplicity.

- 5.77: Incorrect; a parallel cable ONLY could be used, not additional converter stations, to give double circuit type redundancy. This would need to be designed in from the outset though. There is some inherent security in the converter station, in that a single pole outage only results in a 50% loss of transmission capacity.

Islands

We have no specific comments on the Islands section.

Yours sincerely

Danielle Lane
Head of Regulatory & Stakeholder Relations UK
DONG Energy

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	Stuart Cotten (01757 612 751)
Company Name:	Drax Power Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We believe that the Workgroup has made good progress to date in identifying, and providing preliminary analysis on, options for each part of the Modification (i.e. sharing, HVDC and island connections). There is still a considerable amount of detail to be developed, particularly on sharing and the potential use of a diversity factor, prior to the commencement of the Cost Benefit Analysis. Please see our answers to the specific questions raised by the consultation (below).
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We believe it is too early to state whether the original proposal better facilitates the Applicable CUSC Objectives. We shall provide further comments on CMP213 when the Workgroup has had time to consider the views expressed in consultation responses and the proposer has had time to consider which (if any) options highlighted in the consultation (or in industry responses) they wish to adopt as part of the original proposal.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We believe implementation in April 2015 would allow parties time to react to forecast changes to tariffs (e.g. make decisions on TEC reduction or closure). In contrast, implementation in April 2014 would provide too little notice for users to react to tariff changes, given their obligation to provide notice to National Grid at least one year and five days prior to the Charging Year. Any implementation option that occurs midway through the TNUoS Charging Year is highly undesirable as this would not align with TEC reduction / closure decision timescales.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	Yes, the Workgroup has considered an adequate range of options. However, we believe that further consideration is required on the mechanics of a diversity factor and how this would be applied in the TNUoS tariff calculation. In addition, we believe further analysis is required on the merits of diversity at a local level. In particular, the correlation (or counter-correlation) of load factors of different plant types (some, of which, have not yet been subject to large scale deployment) that are geographically concentrated.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Yes, we believe the Workgroup has identified a sufficient number of options for consideration. However, there is a lack of analysis on generator cash-flow implications for each option (e.g. where an ex-post reconciliation is considered). In addition, there needs to be a better understanding of how generators will treat the variable ALF methodology in their cost base. We continue to have concerns over the introduction of a long-run tariff that is directly affected by short-run dispatch decisions.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No, we have no additional views to those expressed by the Workgroup. We believe that all plant should be subject to the Peak Tariff, although the tariff applied to each plant should reflect the assumptions contained in the SQSS. This will ensure that the application of the Peak Tariff evolves as generation technologies develop.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Overall, yes. However, please see our responses to Questions 1 and 2.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	Our main views can be categorised as follows: 1. ALF: The methodology should use a Generic ALF approach that reflects the characteristics of different plant as captured in the SQSS for the same reasons set out in the Workgroup report. 2. Diversity: The methodology should contain a diversity factor to ensure that sharing is only reflected in a user's TNUoS charge where it is technically, and probabilistically, feasible. 3. Peak Tariff: We believe that all plant should be subject to the Peak Tariff, although the tariff applied to each plant should reflect the assumptions contained in the SQSS. This will ensure that the application of the Peak Tariff evolves as generation technologies develop.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	Yes, we believe each of the options could work.

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Both the "most constrained boundary" and "multiple boundaries" approaches appear plausible. The original proposal, which places all converter costs into the wider locational element of the tariff, appears the best evidenced at present. We agree that it is sensible to pursue an option that removes some elements of the converter costs. However, more analysis is required to develop evidenced based justifications.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes, although please see the answer to Question 1 (above).
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, the range of options identified appears reasonable. However, given the difference in technologies to be employed, geographical attributes and, thereby, associated costs of each island link, we currently believe the case for generic expansion factors is very weak. Additional analysis is required to develop a justification for generic expansion factors if such proposals are to be taken forward.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes, the range of options appears reasonable. However, we question the appropriateness of the SO “anticipating” changes to the generation background. We believe the charging methodology should attempt to reflect, as far as possible, the physical attributes and capabilities of the system.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, the range of options appears reasonable. However, at present there appears to be little justification for applying any of the alternatives.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	To date, the original proposal appears to be best evidenced.

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We believe implementation in April 2015 would allow parties time to react to forecast changes to tariffs (e.g. make decisions on TEC reduction or closure). In contrast, implementation in April 2014 would provide too little notice for users to react to tariff changes, given their obligation to provide notice to National Grid at least one year and five days prior to the Charging Year. Any implementation option that occurs midway through the TNUoS Charging Year is highly undesirable as this would not align with TEC reduction / closure decision timescales.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	We do not believe that a transitional approach is appropriate. The current process for notifying TEC reduction / plant closure, implemented by CMP192, should prevail. As such, the implementation timescales for CMP213 should work around this process. One year and five days has been signalled as the minimum notice period required by National Grid. Changing this process "at will" simply makes a mockery of the justifications set out under CMP192.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	Mark Cox
Company Name:	EDF Energy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The matters concerned comprise the most complex code/market rule consultation we have yet seen since Vesting. It is clear that the workgroup still has much to do, including the definition of alternatives, of which there will be a number. There will certainly need to be a second consultation following this. It may be that that second consultation will comprise a slightly more compact and targeted document, which can help ensure engagement.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	CMP213 Original attempts to better facilitate the Applicable CUSC Objectives, but does so imperfectly. We do agree that now that SQSS has been amended under GRS-009, there is a need to update the charge calculation method to reflect that. There is also clearly a need to update the charge calculation method to reflect new HVDC technologies, and new Island connections. CMP213 Original attempts to address each of these. Overall we consider that the proposal is more cost-reflective, but it has flaws in the manner in which it treats intermittent generation and sharing more generally, and can be improved. We expand on this later on in this response. We believe that a variant of CMP213 is likely to be eventually chosen and implemented, once specific WACMs are defined, and that this WACM should be able to better facilitate especially (b), in that it better facilitates cost-reflectivity in the transmission charges, and, as a result of so doing, competition in generation, and (c), by ensuring that the use of system charging methodology properly takes account of the developments in transmission licensees' transmission businesses (regarding new topologies and technologies).

	For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Yes. We would comment that if implementation should for any reason not prove feasible by 1st April 2014, then it should be on 1st April 2015, as a mid-year implementation would be very untidy in relation to TNUoS charges.

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	The workgroup has considered this matter. It seems clear that the concept of sharing by means of the application of a load factor to the year-round tariff element, does not reflect reality well where locally, one type of generation is dominant. Evidence is needed on the extent to which wind and wave power exhibit any counter-correlation. More detail is needed to better understand how each of the sharing and diversity alternatives work. We believe no sharing can safely be assumed amongst generation connected to local (pre-MITs) circuits. We therefore believe that local circuit TNUoS tariffs will not require adjustment as a result of whichever variant of 213 is eventually implemented. Generators are, anyway, perfectly free to request a TEC lower than their installed capacity based on, for instance, rarely generating at a wind farm's total site maximum output, if they believe this to be their reality.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	We believe that the proposal, in 213 Original, of the use of load factor alone as a dilutant of the year-round tariff element, is inaccurate – it does not reflect reality well. We would like to see the workgroup concentrate on working up methods 1, 2 and 3 of improving ICRP in the core of CMP213, further. These seem to be the areas where there is still the most work to do, and where there is strong scope for viable WACMs. We do agree with the comments in the consultation document on the concept of the application of load factor to the residual charge, which the Workgroup has decided not to take further; table 16 illustrates well the manifest drawbacks of this concept. We also agree that there are numerous potential flaws associated with both the Metered Output and FPN approaches to determining the ALF.

Q	Question	Response
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	The relevant question is to what extent in future, if there are large volumes of intermittent generation, NG might rely on some portion of it, even if small, to meet ACS peak demand. We note that the GSR-009 consultation stated, *"A scaling factor of 0% for intermittent generation is simplest to articulate and implement, but analysis of the wind data supports the inclusion of wind generation at 5% of Registered Capacity. This is because, against the dataset used, the GB 2020 wind fleet will be at 0-2% total output for an average of only 4 hours per year; whereas it will be at 2-7% output for an average of 160 hours per year".* We do consider this points to evidence in favour of intermittent generation, if it is to be treated as a single class, being exposed to the proposed Peak Security element of the TNUoS tariff at around a 5% level, and not the proposed 0% in CMP213 Original. We note that if there is significant tidal generation in future, and it continues to be included within the class "intermittent", then further review may be necessary.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We have set out our views on sharing in relation to local circuits in our response to question 1. We do believe that annual load factor alone is a poor indicator of the costs caused by incremental MWs in particular areas of the wider system, and that generation type (bid price) matters as well, as does the amount of other generation (with a different bid price) in the same area and the degree, if any, of counter-correlation – i.e. diversity is indeed key. Method 1 as referred to in the consultation is not yet well-defined, but is worth developing further as a priority. Methods 2 and 3 as referred to in the consultation both have merits, and we would like to see the workgroup's work programme as from now concentrate on further defining, and analysing the effects of, methods 1, 2, and 3 for handling diversity.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	We would like to see methods 1, 2, and 3 regarding how to take account of diversity of plant types, developed well as a priority for the workgroup – the workgroup's work on islands and HVDC issues is more well-developed, by comparison.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes, the WG considerations in this area are well documented. The original CMP213 proposal appears optimal in this respect. The correct approach based on cost-reflectivity, is to take the annuitized unit capital cost (£/MWkm/year), including the converter cost as well as cable costs. The converter costs are clearly linked inherently to the technology, and so should not be excluded. The HVDC link is not being built in order to be able to route, or marshall, power. DC has been selected because onshore OHLs can no longer readily be consented. Therefore the route has to be sub-sea, and being elongated, AC is technically infeasible due to cable capacitance. The choice and cost of the HVDC link is inevitable, and the technology choice was not made for reasons of system control. The “controllability” of the HVDC link is largely irrelevant; its value lies in alleviating constraint costs that would otherwise arise, which would significantly exceed its capital cost. As to any comparisons with quad boosters, one of these would not have been built where the West Coast HVDC link is being built. If the converter cost were to be excluded, economic inefficiencies would result from the lack of cost-reflectivity in this regard. The converter cost represents real money which someone, somewhere has to pay for. The need for a new HVDC link is caused by generation North of it. HVDC converter stations must therefore form an integral element of the locational signal for these transmission circuit types, otherwise generators will be unable to internalise the transmission network cost impacts of new plant location (and existing plant closure) decisions. The cost of converter stations as a proportion of the whole will vary considerably for each HVDC circuit, depending on its length. In essence the converters represent a pair of fixed costs. Cost-reflectivity is best served by calculating a unique expansion factor on the transmission network for each of the very few HVDC circuits that come to exist.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	It is important that the impedance chosen for each link is correct, and results in flows along the HVDC link that mirror those likely to obtain in reality. We have no additional options to propose.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	If an island is connected by HVDC, we agree with CMP213 Original as developed by the workgroup, so that the expansion factor for that technology is used based on annuitized cost. The need for such island links is patently driven by proposals for development of new generators on the islands, and not by demand growth. Regarding the selection of the impedance for HVDC island connections in the DCLF model : we support the application of the same approach as for the HVDC bootstraps (see reply to question 7).
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	See reply to question 7.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes. We believe that CMP213 original, which says to maintain the existing MITS definition, is the best approach to determining which island connections are classified as "wider" (and not to apply "sharing" to local circuits). We do have a concern that where an island does qualify as wider under the existing charging definition (of what is wider), there may be limited, if any, true generation diversity in terms of year-round output counter-correlation. It has not been established that wind and wave power counter-correlate, and there may be only limited existing, small-scale fossil plant (which may be closed medium term). The sharing factor for TNUoS charges to generators on islands that do qualify as wider need to reflect the degree of expected counter-correlation amongst generation technologies there.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	As to any island connections which do qualify as "wider", we agree with the Workgroup that where there is no redundancy in their connection, their expansion factor should be scaled down by 1/1.8, so that the application of the global security factor of 1.8 in the charging model doesn't lead to an unfair outcome.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We support CMP213 original in this respect : the island expansion factor should be project-specific, based on the actual cost of the transmission project. We do appreciate that a result is that each project cannot know its *exact* TNUoS until close to the time of build. The advantage of this approach is that it is the only approach to this aspect that is fully cost reflective (thus meeting objective b). Offsetting the early uncertainty, the charges would be stable once set. As to whether new connections might be cheaper - the past is not a guide to the future, and most commodities are only becoming more expensive. Past reductions in the costs of some forms of connections, especially submarine cables, may not be indicative of ongoing, future reductions.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	If an island's connection is local, whether or not it might later qualify as wider if some more generation or demand came along (triggering grid expansion) is not something that NG should be attempting to forecast, or pre-judge. National energy policy is not sufficiently static for this to be reasonable. Moreover, NG would be subject to various pressures in making such an assessment. This possibility would be likely to politicise the electricity landscape, and to be damaging to certainty and stability. It may not lead to efficient outcomes. Anticipatory changes would have to apply system-wide, and would have to "anticipate" a MITs node becoming a local one, as well as vice versa. The problems are manifest. We would not support WACMs embedding this type of "anticipatory" assessment/allocation.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes, and we agree with the original on this matter. We do not have any other proposals or options that we would like to be considered.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	We agree with the proposed reduction in length of a connection to the mainland by 1.8 where it is a single link.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We think that implementation should be in April 2014 if a final decision is made by Ofgem by the end of September 2013, otherwise from April 2015. We do not agree with the concept (options 1 and 3) of a mid-year, i.e. non-April, implementation date – that would not fit with the charging year that users are used to, or with the way that TEC charging is and always has been structured.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Our view is that following the Ofgem decision, the usual CMP192 based penalties for early closure, or early cancellation of a pre-commissioning generation project with a signed connection agreement, should still apply. The risk otherwise is that generation projects which for reasons other than CMP213 are considering terminating or closing, would be able to misuse the transitional arrangement. This would undermine the new user commitment that has only just been introduced after extensive national debate. There would be a risk in consequence of, in a number of cases, exposing consumers to additional costs from stranded transmission assets, especially as regards speculative new projects.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No, but we would particularly like to see methods 1, 2, and 3 as to how to accurately take account of plant diversity in the improved ICRP model, fully worked up into WACMs by the Workgroup as a priority, as this is where there is the most work still to do, and it is fundamental. Our views on other possible WACM components are contained in the answers to the questions in this consultation.

Q	Question	Response
Do you have any other comments?		No

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	Michelle Dixon
Company Name:	Eggborough Power Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	It is difficult to comment on these complex issues without having been party to the discussions, but we hope that the following comments are helpful. Generally Eggborough Power Limited (EPL) are concerned that the tone of the work seems to be looking at ways to lower the transmission charges to renewable (or intermittent) plant in a move away from cost reflectivity. Ofgem's general approach to monopoly charges has focussed more on the capacity element than any commodity usage, arguing that the TO builds its network for meeting a peak system usage and those connected must pay, irrelevant of their technology. As we move forward, with wind expected to achieve higher load factors and coal/gas becoming more variable, there is a risk that the methodologies proposed will have simply placed more cost onto the existing plant with no economic rational. Using historical load factors seems to move charging towards a backward looking, potentially discriminatory regime. The principle of equitable, cost reflective charges should be maintained. We understand the principle of not charging companies for assets that are not there, and agree if the TO does not provide the peak capacity on the wider networks the parties should not be asked to pay for it. However, this could be done by having "firm" and "interruptible" access rights, rather than giving a blanket discount. That would possibly allow other parties to opt for similar rights. Sharing is a well established principle in gas, where the "interruptible" products have been used for years. We support

	generators being able to pay lower charges for interruptible rights, but the interruption is a business risk that a customer may or may not choose to take on. The idea of using load factors is highly risky and has the potential to be very wrong; look at the changes in gas and coal stations over the last year. EPL does not believe that intermittent generators should not be exposed to paying for assets if they do utilise them. The calculated sharing factor seems to put the TO in charge of saying who is sharing capacity, rather than possibly looking at the potential to share (wider capacity) and then offering reduced tariffs (say via a tender) to the parties who wish to have less firm access rights. On the HVDC links, EPL believes that the converter costs form part of those links in the same way that the local substation used by a power station forms part of its charges if it is the sole user of the assets. However, we believe that work done on load flows will need to try and establish a "reasonable" approximation to the modelling on the AC network. EPL has no comments around the island connection work.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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.* On balance, given the current status of the proposals, EPL does not believe that the original modification better fulfils the relevant objectives as it does not appear to be cost reflective when compared to the base line (objective b).
Do you support the proposed implementation approach? If not, please state why and provide an alternative	

suggestion where possible.	

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	It looks as if the workgroup still has some way to go on their discussions. Generally EPL feels that the methodology should be technology neutral to maintain its cost reflectivity.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Without being at the meetings, we suspect the workgroup has given due consideration to the issues.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	As noted above, EPL has some concerns about generators who can access the system at peak times not paying for the investment that allows the TO to accommodate peak flows. While there is some implicit sharing occurring, we are not convinced as the system develops that what is really needed is some form of “less” firm access rights, with associated lower charges. At times in the past there was a push by Ofgem to move the market to access rights that could be explicitly traded. We were never of the view this could work, but we think a more pragmatic approach could be to consider non-firm rights. Under such a regime the generator would get discounted charges in return for the TO being able to call him off at times of high system usage or constraints. At the current time the TO can manage the system using the BM, bidding plant off, but not having to face the financial consequences itself.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	EPL has no specific item to add to the workgroups considerations.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	There has to be good reasons to treat different types of generators differently. When a wind farm or a coal fired plant is generating the power flowing over the wires is MWs and it therefore appears to be unduly discriminatory to treat one differently to the other. As noted above we feel very uncomfortable with the idea of using historic load factors or operations to dictate prices going forward. This could create significant price volatility (for example wind all had a high load factor last year so has a low charge this year, but it turn out to hardly run). The RIIO framework already appears to make it more likely that monopoly charges could suffer from increasing volatility and the regime should do nothing that would make that situation worse. EPL is also unclear what the incentives would be on plant. AT the current time the TNUoS charges incentivise connection in the south. Would getting low prices at a certain point of load factor cause odd operating regimes? My load factor will be too high if I run in March, and given how high the prices are I best stay off the system?
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes. This appears to be a tricky issue. EPL does feel if reduced charges are required to offer a further subsidy to the windfarms connecting into these wires then it would be best if we were explicit about that subsidy.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	It looks from the report as if the group are still considering these issues.

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The group appear to be trying to create a model that will allow the new links to fit into the existing methodology, which seems reasonable.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes, though we recognise that the way the connections were configured historically may create some anomalies. However, the same is true for conventional generators who also get different charges arising from historical engineering decisions.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	EPL will wait to see the additional work of the group before making further comments. However, we agree that where the network expands using HVDC links those links should all be treated in the same manner.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	EPL would favour a 1 April implementation, but are indifferent if it is 2014 or 2015 on the condition that the parties have sufficient time to consider and plan around the indicative charges.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Whether a transition is needed depends on the solution.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	*Neil Kermode – Managing Director - Neil.Kermode@emec.org.uk*
Company Name:	***EMEC***
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The consultation is useful as tool to comment on the development of the project TransmiT issues in the CMP process but does not give enough detail for respondents to realistically assess impacts of the Original. This statement is even stronger for the likely alternatives. It would be unfortunate if stakeholders did not have a chance to influence any material change to the direction of the process once sufficient detail becomes available.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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;* As far as the Scottish Islands are concerned there is no set methodology with which to compare the Original. It is probably fair to say that the Original may yet be changed after this consultation and before its submission to the CUSC panel. However if the Original does not allow for local sharing by load factor (or otherwise) and, in turn, leads to high and/or volatile locational charging and consequently an increasing and disproportionate gap between Islands and the rest of the GB system then there would be a significant issue as far as competition is concerned. *(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); The Original, in its present form, may not offer a consistent signal for cost reflectivity when looking at the way expansion factors are calculated for traditional network assets and newer technologies. *(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.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	It would be desirable if implementation was 1st April 2014 but in order to resolve key issues it may mean that some of the parts of the later process need to be shortened – or a period of transition allowed – to allow for further work in the Workgroup.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	The important phrases in the question appear to be *' .areas dominated by one type of generation'* and *'including local circuits'.* For Diversity, the analysis seems incomplete as there is a basic assumption that intermittent generation cannot share and - on a year round basis- thus remains perfectly correlated. All are deemed 'must run' and that all will be running together and with similar Load Factors. Local Sharing – would introduce a sharing factor for Local circuits, including Scottish Islands, which would depend on modelled outputs assessing scenarios with only intermittent renewable generation (and some local demand). As 'Other options' it may be worth suggesting that wind generating plants sited over a wide geographical area could also be modelled for anti-correlation of output –rather than assumed as 100% correlated (all running at the same time) in 'Diversity' and, so far, in the Island model

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	The WG has sufficiently reviewed the options for the calculation of ALF.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No additional suggestions
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Forward looking application of sharing is an integral part of Local sharing otherwise sharing – in charging terms – could only be applied AFTER other generators of different types joined the circuit. In the rest of the (Wider) network sharing is generally anticipated. This could be further developed in the WG. It is noted that the issue of local/wider definition and how that should be dealt with as far as application of ALF is concerned for Islands is ambiguous in the report. This may mean that responses to this consultation may lack a degree of clarity –reflecting confusion regarding the consequences of the stance of the Original and Islands meeting the definition of Wider. (See 6.101 p 130 and table 19 p 122-123 of the WG report). Work needs to be done in the WG to clarify this issue.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	It may be that: Sharing, if it is truly reflective of use and of generator type, should apply throughout the system including in parts deemed local – but serving several generators. Or That cost reflectivity is best served by using a simple, but generator specific, load factor – as in ALF, whilst adequately representing networks which, whilst they may be on the periphery, are integral parts of the GB onshore transmission system.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	See our response to Q12. We do not consider that the argument that HVDC links, which parallel and are fully integrated with the GB onshore network, should be treated the same as OFTO arrangements to have validity. Consideration of factors to be included in the expansion factors of AC and HVDC onshore solutions should be treated in a consistent manner. It appears that an overly simplistic view was taken on HVDC converter stations – i.e. as they are more expensive than AC substations their costs should be fully locational. However taking an overall view of HVDC compared to traditional AC, not only is the technology superior, costs are in line if not lower than AC and environmental impact is much less. Where HVDC offers the optimum solution its implementation should not be impeded by charging methodology.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	The basic premise that that HVDC load flows are linked to AC network boundaries is covered. There could be further consideration of the benefit in network management offered by HVDC technology and how this might be reflected in locational and non-locational TNUoS.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Referring to 5.73 – 5.78 p114 The cost of single v double HVDC links has not been 'bottomed-out' with hard data – it may be worth looking further at this.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Should the SO or TO's be allowed to build an HVDC link which would be more expensive (in terms of Locational TNUoS for triggering generators) but cheaper in real cost terms than a conventional AC link (plus its fixed infrastructure) ? It would appear wrong for this to happen, especially considering the technical and environmental benefits of HVDC. Should specific HVDC cable expansion factors be used considering DC cables are cheaper than equivalent AC, yet generic AC cable/overhead factors lead to lower TNUoS?

Q	Question	Response
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Though the Original includes Islands classed as Wider in the potential reduction in Locational TNUoS (compared to the Status Quo) afforded by ALF – there have been indications from WG discussions that if all (or even some) of the Scottish Islands triggered ALF that 'Diversity' (as described in the table for Q1) would be introduced into CMP213 in order to 'correct' the' anomaly'. It is worth looking closely at table 19 produced on P122-123 for the range of issues in Islands but in particular at '5. Sharing' and 'Action Required'. It is interesting to note that for 'iii Maintain Existing Definition' (apply Wider when and if an Island 'qualifies' the same Action Required as All Classed Wider. See also response to Q4 The view expressed in 6.101 (led by National Grid) that tariffs should be similar whether Islands are classed as local or wider needs further development.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	There may be some problems in how the potential alternatives may be worded. Though option vii is described as no potential alternatives being considered, this was not the case for option viii which is described as having support. It may depend on how redundancy is measured if 2 single (not double circuits) comprise a Wider link to an Island. If each circuit was only half or less of the total TEC connected then would there be redundancy?
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Arrangements already in place for Offshore (OFTOS) are often used by some WG members to argue that Island (Radial) links should be treated the same. That translates to inclusion of Converter Station costs within the Expansion Factor and hence locational TNUoS. We believe that this thinking is flawed and does not take into account significant, and critical, differences between Island's relationship to the onshore GB network and connections to offshore wind. We do not feel that the arguments for including all Converter Station costs for HVDC but excluding substations and Quadrature Boosters in AC been adequately justified. We believe that there needs to be more consideration, including further analysis, of links which compare AC versions of all or parts of links with HVDC alternatives insofar as capital cost versus eventual TNUoS are concerned (5.46-5.54 pp110-111). This is also pertinent to Q6 above.

Q	Question	Response
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Whilst the MITS definition is linked to the level of sharing allowed for in the charging methodology this may need to be considered in a more forward looking manner.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Could the Island sharing modelled in the ICIT work be expanded to look at sharing generally between Intermittent generators and also look at how a single renewable generator type made up of plants spread over a wide geographical area may have a degree of inbuilt counter-correlation?
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	• If Island sharing is to be used as a factor within the methodology it would need to be codified, that is transparent and predictable for those who need to know what their TNUoS is likely to be. There would be a concern if sharing could only be applied after the fact (only after other types of generation actually joined) or if sharing/not sharing was effectively determined by the TO on a case by case basis – which may lack the necessary transparency needed by generators , not least for investment purposes. • Where Islands conform to the definition of Wider there should be no reason why they should not be treated as any other part of the onshore network. • Island links, where they are radial HVDC, should be treated in the same way as parallel 'bootstrap' links as far Expansion Factors are calculated. • For all links the methodology would need to avoid the prospect of uncertain and volatile charges for generators in certain areas – one of the major underlying reasons for such are likely to be unstable and rising single project costs which are then input as the Expansion Factor. It is difficult to compete effectively if others can make use of smoothed out (averaged) costs which are far less prone to sudden and unexpected increases in the locational TNUoS. • A Security Factor of 1.0 (whether Wider or Local) should be used for links where there is no redundancy.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	1st April 2014 with transition option Otherwise if no transition option then 1st April 2015 would be more feasible.

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	See Q 16. Yes if implementation on 1st April 2014 – then shorter notice period allowed.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No
Do you have any other comments?		No

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	*Paul Jones paul.jones@eon-uk.com*
Company Name:	*E.ON*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	Please see below in our response to the individual questions asked in the consultation.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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.*

	No, mainly on the grounds that we believe that it is not appropriate to charge on the basis of load factor, especially a historic one. We do not believe that load factor is the sole determinant of the amount of constraint costs connection of a certain plant could cause. Also historic load factors do not represent future load factors.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	As no specific implementation approach was specified, please see the answer to Q16 below.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	The range of options has been identified but not fully explored in all cases. There appears to be more work to do on the options that take into account the amount of diversity in an area along with the load factor of plant. Presumably this will be taken forward by the working group as a next step.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	It has reviewed all of the options. However, we believe that a backwards looking ALF is problematic as an indication of a Load Factor going forwards. If investment is made on the basis of a view of how LFs will affect constraint costs then it must be forward looking. One aspect that the workgroup doesn't seem to have considered fully is what the load factor signal is seeking to achieve in terms of generator behaviour. If a station is to be charged on the basis of its load factor then we would expect it to be able to react to this signal in some manner. In the current methodology the signal is seeking to influence generator build and closure decisions. A generator can react to the current price signal by choosing to build a new power station or close an existing one at a particular location. If load factor is introduced as a charging parameter, then the aim must be to influence behaviour accordingly with respect to that load factor. If a generator is unable to react because it is based on historic performance, then it is not clear why the signal is being sent and what it is aiming to achieve in terms of efficient behaviour on behalf of generators.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	Intermittent generation should be exposed to the peak security element to the extent that it drives investment made to support peak usage. In the work undertaken to support SQSS change GSR009, a 5% availability factor was assumed for wind, but was scaled to 0% as there was little practical difference. It may be appropriate to applying 5% for the peak charge or to keep the treatment as proposed and to review the situation if the contribution to peak increases in future.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	As we state above for question 1, the sharing options haven't been fully explored and more work needs to be done on how to potentially reflect diversity going forward. Also, further work could be done on whether a forward looking Load Factor would be more appropriate.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	Assuming that the LR/SR cost equivalence assumption is robust, the methodology should seek to reflect different characteristics using more than a load factor relationship as diversity of plant in parts of the network and associated bid prices clearly have a significant influence too. Rather than trying to apply individual characteristics through ALF, it may be better to reflect effects more generically. After all, investment in the network will not be made on the basis that individual stations are predicted to be generating at precisely the same output that they have achieved in the previous 5 years, so why should the charging seek to do so? We see merit in exploring a forward looking load factor solution with a simple cash-out mechanism for overrunning, if load factor is included as a parameter in the proposal.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	Yes.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.

Q	Question	Response
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	We believe that there is a case for removing some of the converter station costs from the calculation of the expansion factor, but only where it is clearly demonstrable that they would have been incurred for an AC equivalent and charged through the residual too. This should be assessed on a case by case basis for each HVDC circuit as circumstances of each link are likely to be very different. It would certainly not be appropriate to treat these as 400kV overhead lines. The model should seek to ensure that the HVDC's impedance is represented so that a "fair share" of flows occurs on HVDC assets when it is run. The approach set out in the original at present seems to do this most appropriately.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	Yes.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.

Q	Question	Response
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	There should wherever possible be a consistent approach with HVDC elsewhere. We are less concerned about how assets are classified, as long as a consistent approach is adopted across the charging methodology. For instance we believe that where it can be demonstrated that local assets are shared that this should be appropriately reflected in charges. However, we do not support an anticipatory approach to sharing.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We would not support a mid-year implementation approach. We continue to believe that major charging changes should occur with effect from the beginning of a charging year. If there is time to implement by April 2014 then this would be acceptable as long as sufficient notice of new tariffs is given to participants (see answer to 17 below). Otherwise, implementation should occur in the following April.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Sufficient notice of probable charging effects should be given to allow stations to make TEC reductions where appropriate in good time without fear of a penalty charge being applied under the CMP192 arrangements.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No thank you.
Do you have any other comments?		No thank you.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	Mike Davies 020 7484 8573 Mike.davies@futurelectric.co.uk
Company Name:	Future Electric Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We appreciate the considerable work done to date on this modification proposal. Our one principal concern is that this has not yet looked at the financial implications of the changes under consideration. This modification is complex and there is a risk of unforeseen consequences. It will be too late in the process when an Economic Impact Assessment is available to address apparent defects. Despite the potential delays, we urge the workgroup to reconsult with the benefit of some meaningful economic forecasts.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	Without some economic analysis we are unable to tell if the original would definitely better facilitate the Applicable CUSC Objectives in a number of respects. In specific relation to the proposed treatment of HVDC lines however, we firmly believe it does not better facilitate the Applicable CUSC Objectives. More details appear below.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Early implementation is far preferable to delayed implementation although we would not wish to see this happen at the expense of full consideration. Where we see the potential for flex is in the required notice period from a decision up to the point of implementation. We consider April 2014 to be a realistic target.

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	We view the distinction between types of generation as important. For example low carbon generation can be from quite different technology types where more diversity may exist. There is a risk of over-building as a result of taking too simple an approach to this.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Yes we do.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	We question if the use of the two part locational model is needed but it would be very helpful if economic outputs could be provided. These would enable us to see the effects of different treatments on different generation types in differing locations around the UK.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Where quite different technologies such as wind and wave/tidal can both exist on a system, there may be merit in more work on a suitable sharing model.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	As mentioned above, more work may be useful on the interaction of different types of low carbon generation.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We consider that a fundamental issue is being overlooked in the pursuit of a theoretical goal. For a TO, their licence obligation requires them to choose the most economic and efficient connection. In a case where the costs of AC and HVDC alternatives are close, a generator triggering such works should be indifferent to the choice made by a TO, especially since he cannot influence it. Therefore the choice of technology by a TO should not impact the generator in any way. Here the proposals do not take this simple fact into account. In the absence of an economic analysis it is unclear exactly what effect the different alternatives might have but it is reasonably clear that they would have some distorting effect. We feel this is clearly wrong.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	We reiterate our point above. It is not right that technology choices made by a TO should impact generators unable to influence those choices.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	See above.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The approach adopted must not be allowed to distort generator charges when compared to the use of AC alternatives.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	As far as we can tell in this complex paper, it has. This is subject to our comments about sharing in the context of different renewables technologies as mentioned above.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes we consider that the Workgroup has considered all relevant options and potential alternatives.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes we do, subject to our comments about the approach to HVDC above.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	This is one of the areas in particular where it is difficult to assess the impacts of different approaches on TNUoS charges without some economic analysis. That would go to the heart of the CUSC objective about facilitating competition.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes we do, subject only to our specific comments above on HVDC, sharing and some economic evaluation to support alternatives.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	Local/Island sharing- which should be consistent whether they are local or wider HVDC Expansion factors consistent with AC onshore technology.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We favour Option 2 which is near term but we consider allows time for more work to be done.

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	No we do not consider a transitional approach is needed.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No we do not propose to raise a Workgroup Consultation Alternative Request. Should the Workgroup take on board our comments above then members may wish to raise an alternative themselves.
Do you have any other comments?		Once again we wish to thank the members of the Workgroup for all their time and effort in developing this complex modification.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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Please send your responses by **15 January 2013** 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

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:	**Simon Lord** Head of Transmission Services GDF SUEZ Energy UK-Europe Tel. +44 (0) 1244 504601 Mob. +44 (0) 7980 793692 simon.lord@gdfsuez.com
Company Name:	GDF SUEZ Energy UK-Europe
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*Original No* *Method 1 No (further definition required)* *Method 2 Better* *Method 3 Best* *The original has two key ingredients:-* ***Load factor.*** *The load factor is used to reduce the location element of the transmission charge. This is not cost reflective in that in areas with low or no diversity of plant type a reduced location charge*

	is applied to low load factor plant when in practice significant transmission reinforcement can be required. In some circumstances an element of poor cost reflectivity could be accommodated based on the simplicity argument. In this situation though it goes to the heart of the modification and would favour low load factor plant in a zone when in practice high load factor plant with a different characteristic and/or fuel type would lead to no or limited transmission investment. ***Dual background*** *The load flows that are used to calculate the peak and year element are based on two separate backgrounds. One is based on peak flows excluding intermittent plant and the other is based on SQSS set parameters that are an approximation for a full cost benefit calculation.* *We believe that there are two issues with this approach.* • *Intermittent generation is not charged the location element of the peak security load flow. We believe that there is a compelling argument that intermittent generations should contribute to the peak security element. Absent changes to demand (given a compliant system as at present) only reductions in conventional plant lead to investment for peak security, one main driver for this is additional intermittent generation. Additional intermittent generation with low variable cost reduces the energy need from conventional generation and over time the volume of this type of generation available. Reduced conventional generation increases the need for reinforcements for peak security. Given this strong relationship we believe that only a single back ground should be in all scenarios or intermittent should be charged for the peak scenario.* • *An incremental methodology is based on a single back ground. The duel background is not mathematically rigorous as data from each independent back ground is added together which, whilst creating a charge, is not an appropriate use individual back grounds.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	*N/A*

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	*Yes the group has considered the geographical issues and arrived at a methodology to incorporate sharing based on a number of solutions. Whilst the cost is based on an incremental methodology the sharing need not be based an incremental methodology. The relationship in Method 1 includes a type of incremental sharing where full benefit is given to plant based on the ratio of carbon/low carbon plant in a zone. Indications are this may be a "flip flop" type approach with all zonal km either shared or not shared but further work is required to define the exact relationship. Methods 2 and 3 include an appropriate sharing based on analysis with method 3 on a zonal basis producing the best solution.*
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	*Whilst the group has considered the various options for the calculation of ALF we do not believe that any of the proposals reflect the ALF used in planning timescales and all methods will result in arbitrary charges based on historic plant operation. ALF needs to be used in combination with bid-offer differentials in Northern zones and offer-offer differentials in southern zones for it to reflect the relationship to constraint costs and hence transmission builds.* *Analysis has clearly shown the relationship between constraint costs and bid price, this is not captured by any solution based purely on ALF.*
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	*Intermittent generation is not charged the location element of the peak security load flow. We believe that there is a compelling argument that intermittent generations should contribute to the peak security element. Absent changes to demand (given a compliant system at present) only reductions in conventional plant lead to investment for peak security, one of the main driver for this is additional intermittent generation. Additional intermittent generation with low variable cost reduces the energy need from conventional generation and, over time, the volume of this type of generation available. Reduced conventional generation increases the need for reinforcements for peak security. Given this strong relationship we believe that only a single back ground should be in all scenarios*

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*Yes although a subsequent modification could consider sharing within the two broad plant categories. E.g. low carbon category could consider tidal and wave interactions at a local level.*
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	*We believe that reduced transmission investment is driven by the combination of generation type in a zone. It is the generation type (fuel source, load factor, bid and offer prcies etc) that drive reduced transmission. Thus an appropriate methodology could charge all generation in a zone based on their impact on sharing where this is done it should include both load factor and bid price. One cannot be used one without the other.* *A simplification of this is to charge all generation in a zone based on the combination of plant type in that zone. This will deliver the right message where parties considering location need to take account of the characteristics of plant in the zone and zones where power will subsequently flow. Method 3 where the benefit of reduced transmission investmentis shared on a zonal basis produces the best result.*
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	*Yes*
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	*Yes*

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*Yes*
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	*As per the original*
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	*We believe that sharing should be allowed on local circuits where it is included in the design of the connection and can be objectively justified. Simply classifying Island as 'wider' to benefit from wider sharing is not cost reflective and will result in inappropriate charges if sharing is based on the original proposal.* *We believe that the litmus test for sharing is that it should work for island. Method 3 works for islands and would result in shared benefits for all island generation where there is diversity of fuel source. Diversity with future generation types (e.g. tidal/wind) will need to be subject to a further incremental CUSC modification as to attempt to include it at this stage where there is limited deployment of tidal would add complexity at a time where there is already a multitude of issues being dealt with.*
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	*Yes*

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	*Yes*
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	*Yes*
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	*Yes*
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	*A percentage of the HVDC converter cost should be excluded from the specific cost, based on its equivalence with onshore substations.*
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	*Method 3 has significant merit in that it is cost reflective at a zonal level and will result in transmission charges being better aligned with transmission reinforcement cost. The original and method 1 are relatively poor as they do not reflex diversity to any meaningful extent in a zone.*
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	*We believe that charges should be implemented as per the current methodology. There should bethree months notice of indicative charges with charges only changing on the 1st April.*

Q	Question	Response
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	*No*
Do you have any other comments?		*No*

HIE
Highlands and Islands Enterprise
Iomairt na Gàidhealtachd 's nan Eilean

cusc.team@nationalgrid.com 15/01/2013

Dear CUSC Team

Highlands and Islands Partnership Response to CMP213 Working Group Consultation January 2013

Highlands and Islands Enterprise (HIE) is the Scottish Government's agency responsible for economic and community development across the North and West of Scotland and the islands.

HIE along with its local partners: the democratically elected local authorities covering the North of Scotland and the islands: Shetland Islands Council, Orkney Islands Council, Comhairle nan Eilean Siar, Highland Council and Argyll & Bute Council make representations to key participants on behalf of industry to influence the way in which grid construction is triggered, underwritten then accessed and charged for in the region.

HIE and its partners have been closely but not directly involved with the working group process and the response below aims to provide additional input and comments not already expressed by Working Group members. In developing this additional input we have worked very closely with Scottish Renewables.

Process and timescales

Our view is that whilst the consultation itself is very detailed, there is not yet enough information to understand the implications and "bottom line" of the main Alternatives.

We would like the Working Group to consider release of preliminary impact assessment results, or at least modelled tariffs, prior to submitting the Working Group report to the CUSC Panel. This could be facilitated through TCMF or via some other informal route where the information is released to industry. This would facilitate gathering wider views into the Working Group which itself would in any event be refining and finalising proposals in view of modelling work.

It seems almost certain that there will be a Diversity Alternative or Alternatives, but there is still a body of work to complete before it is possible to address questions such as: the direction of travel for tariffs; volatility implications when plant enter and leave a zone and other outcomes.

We are conscious that these comments also hold for island sharing proposals brought forward by EMEC, Scottish Renewables and ourselves, in so far as the proposals are not fully developed. We therefore understand the pressures the group are under and the balance between consulting before or after something is fully developed.

We would welcome further industry comment as and when these proposals take more concrete shape.

Further specific comments on each part of the proposals are as follows:

Diversity
The proposals on Diversity seek to localise cost reflectivity in zones, giving a sharper cost signal. We accept that it can be demonstrated that relationships between load factor and constraint costs aren't uniform across the network, but we do not accept that the proposed solutions address this. They seek to take account of bid prices but do so in a way that themselves require some, frankly brave, assumptions and have not yet been tested. Therefore we are not convinced that there is an improvement in accuracy, whilst there is definitely an increase in complexity which will also impact on predictability and increase volatility.

Island expansion factors
As you will know, many industry participants remain concerned about the level of potential charges for the Scottish islands, and the targeting of cost risks onto developers (e.g. the assumption that generators need to absorb cost increases after they have placed user commitment and proceeded to build their project, as evidenced by recent events in the Western Isles).

Island developers also feel at a disadvantage to mainland developers where some cost categories are more readily fed into the residual component, but where there is a reluctance to mirror this for radial and island connections. E.g. recent cost increases for the Western Isles link have been attributed in part to discovery of more difficult ground conditions, which it is assumed will be passed through in locational charges. The costs of tunnelling on the mainland are not, however, passed through locationally, presumably in part because these costs are high and specific to ground conditions and so difficult to predict and genericise.

It's difficult to argue that generators shouldn't see a cost signal associated with the choices they make, but the islands at the moment appear captive to choices made by others at a late stage in development making investment very difficult.

Whilst the level of charge is perhaps not something that the CUSC can address directly, relative cost reflectivity, predictability, stability and promotion of competition do sit with the CUSC. HIE and its partners therefore support the Scottish Renewables proposal of generic island expansion factors being considered in more detail by the Working Group; perhaps even that remain fixed or index-linked for a particular asset rather than a price control period.

Sharing and Local / wider definitions
HIE and its partners, along with Scottish Renewables, have participated in the development of a local sharing option for islands and are therefore naturally supportive of it. We will read others feedback on the proposals with interest.

The local / wider debate around islands is largely one that is attached to sharing and how it applies to the islands. One concern is that islands might be dominated by one technology and that there is little sharing. Diversity attempts to address but still has generic assumptions that do not fit the island context or indeed other circumstances that have a mix of low carbon generation with some sharing.

Another related concern is that generic assumptions on transmission investment are less likely to be applicable where there is just one single circuit connection to the mainland, and that in this instance a more specific approach is desirable. If the Working Group were to address this through a change in local / wider definitions, we strongly favour developing a new definition for local / wider in the CUSC as applied to sharing, rather than risk consequential impacts of changing existing definitions. Even with a limited change in the definition, we would welcome further consultation to understand what is proposed and to have a chance to comment.

HVDC

The consultation has a comprehensive set of options for the treatment of HVDC and we don't have any major comments to add.

Process going forward

HIE and its partners along with Scottish Renewables believe that sharing, islands and HVDC should be constructed as if they were separate Modifications so the content of one can't influence the attractiveness of another. The number of possible permutations for one mega Modification inevitably risks either prematurely ruling out options or creating a complex and unwieldy process. We would ask the Code Administrator to consider whether it is possible, without causing further delay, to separate each area and provide equal weighting to developing Modifications for the purposes of submitting to Ofgem for consideration.

Yours sincerely,

Calum Davidson
Director – Energy & Low Carbon
Highlands and Islands Enterprise

In partnership with:
Shetland Islands Council
Orkney Islands Council
Comhairle nan Eilean Siar
Highland Council
Argyll & Bute Council

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	***Alist*air Buchan** **Chief Executive** **Orkney Islands Council** **School Place, Kirkwall, Orkney Islands, KW151NY**
Company Name:	**Orkney Islands Council**
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The Consultation document deals at length with complex issues and provides a reasonable insight into the deliberations of the Working Group without giving a clear indication of the majority thinking on some key issues. Matters covered in it are of interest not just to existing and potential generators but also to a range of stakeholders with interests that will be affected by the outcome of CMP213 – and Orkney Islands Council is one example of such a stakeholder, with an interest in building a local renewables industry, the success of which is highly dependent on the outcome of CMP213. The process should be more accessible to stakeholders with wider interests than the direct financial interest of generators.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	In respect of island charging methodology, there was no clear baseline with which to compare the Original. The Council is concerned that the proposals in the original for a cost-reflective island charging methodology are simplistic, resulting in excessive transmission charges which will deter renewables development in the area of the richest resource in the UK, thus inhibiting competition. No account is taken of the potential for network sharing in the islands, based on different renewables technologies and different locations and local conditions at individual project sites around the islands. It would appear that whilst there are certain arbitrary exclusions from the cost-reflective calculations on the mainland, for example

	the exclusion of tunnelling costs, a different approach is taken in the islands where every effort is made to include everything into the cost reflective calculation. *For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	No Comment

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	No. The Consultation document itself states that full consideration has not yet been given to the Heriot Watt research into network sharing between different renewables technologies in Orkney, and by extension in other islands. The Council welcomes the statement in the document that it is planned to further consider this research. The phrasing of this question, 'dominated by one type of generation', appears implicitly to put all renewables into one category, 'intermittent generation'. The characteristics of the various renewables technologies need to be explicitly recognised, and the Heriot Watt research is a sound starting point for this. It still needs to be further developed, in particular in respect of the simplifying assumption of a single point location for all wind generation, which ignores local conditions which could contribute to counter-correlation.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated Are there any areas that you think may need further development? If so, please specify along with an associated justification.	Yes, the Council considers that all options have been included.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No, not applicable to islands whilst they are local.

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	As is the stated intention in the document, further consideration needs to be given to the evidence presented in the Heriot Watt research on network sharing between different renewables technologies. This should be the basis for a sharing factor which, in the interests of simplicity, should give a sharing factor which can be applied across the board to islands, as with ALF on the mainland. This would also serve the important purpose of giving greater certainty to developers making financial projections for possible projects. This also requires that the island sharing factor is applied on an anticipatory basis, as is effectively the case with the ALF proposal on the mainland. Without an anticipatory basis, there will be a perverse incentive for a developer to hold back in the hope that others will shoulder the initial charging burden.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	The Council believes that it is right to develop a methodology which tends more to reflect usage of the network by different technologies, rather than purely installed capacity.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	The Workgroup has considered a number of fairly technical options, the Council is not qualified to comment on whether this range of options is exhaustive.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	As 6) above

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	As 6) above
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The Council believes that given the widespread benefits to a range of generators, to the System Operator in terms of greater control, and also to Demand at a national level, the cost of HVDC circuits that parallel the AC network should not be locationally charged, but should be socialised. The technical discussions about which elements of converters, if any, to exclude from the cost calculation, are arcane. There is merit in simplicity in charging and there is adequate justification, as indicated above, to socialise the costs.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	As indicated in earlier answers, further consideration and development of the Heriot Watt model is needed.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes, there is straight forward and fairly unarguable logic in applying a security factor of 1.0 for single circuit connections with no redundancy. It is difficult to see any other options worth considering.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	No. The Council believes that, in compliance with EU directive 2009/28/EC, which requires 'reasonable connection costs' for island regions and regions of low population density, in order to ensure they are not 'unfairly disadvantaged', consideration should be given to the option of setting a limit on island expansion factors, whether for AC or DC, relating them to overhead line costs on the mainland. The disparity between projected island charges and those on the adjacent mainland are excessive – on the basis of Redpoint modelling a factor in excess of 6 times the mainland charge. The islands are an integral part of UK territory, with demand as well as enormous potential for supplying renewables to the UK, they should not be treated as offshore generators. The consultation document itself draws attention to the differences, in para 6.93, and the Council strongly supports those comments. The discussion document also rightly draws attention, in respect of island expansion factors, to the need for developers to know in advance of completion what the transmission charges in the islands will be. The absence of this knowledge increases uncertainty for developers to such an extent that it is difficult to see how they can properly plan for projects in the islands, and consequently such plans may not progress. The evidence of delay in island projects is already there, and has now contributed to the deferment of cable completion in Orkney by two years, to 2018. In the Council's view the islands expansion factor should embody a fixed relationship between charges in the islands and those in the nearest mainland zone.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes. The Council believes that the islands must in time become part of the MITS, on the basis of current definitions and because in the future, the islands will be at the centre of an onshore and offshore network of renewables generation, and thus an integral part of the MITS.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	The Workgroup has considered many options for the islands but the overall impression of the Consultation Document is that it has on the whole considered islands as appendages which need to be squeezed into the logic of a transmission charging technology designed for a different era of large centrally-located fossil fuel generators. Despite the growing importance of sustainability, and the direction of travel of Government policy, there appears to be little vision and no recognition of the fact that the UK will increasingly depend on power which can best be generated at the periphery of the UK, rather than at its centre, and that transmission charging methodology should work with the grain of this development, in order to facilitate it. Locational transmission charges send signals to generators which run counter to the necessary growth of renewables at the periphery of the UK, and thus amount to a burden on that development. The islands will in future be a key part of meeting the UK's energy needs, collecting power from a range of different technologies located on the islands and in the waters around them. They would be an integral part – in fact a key part - of the MITS. Charging methodology is supposed to be forward looking and the Council submits that the Workgroup should give more explicit recognition to this than it appears to have done.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	The Council's overall view is that the islands, like the periphery of the UK mainland, represent the future for the power generation from renewables that the UK will increasingly need. A transmission methodology which sends locational signals counter to this is not helpful and is not facilitating the necessary re-orientation of the UK transmission network. The Workgroup has done a great deal of complex work, but within the constraints of the existing charging methodology. Thus in the Council's view there needs to be a) a much greater recognition of overall strategy for achieving a sustainable energy future for the UK; b) recognition of the characteristics of different renewables technologies, the potential for counter-correlation based on these characteristics and on the differing local conditions of different project sites, through further development of the Heriot Watt research; c) an acceptance of the spirit of the EU directive on avoiding disadvantaging islands and peripheral areas in the setting of transmission charges, and hence acceptance an islands expansion factor which incorporates some constraint on the disparity between charges for the islands and those for the adjacent mainland areas.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	No comment.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	No comment.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	Not applicable.
Do you have any other comments?		

Q	Question	Response

RenewableUK
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Web: www.renewable-uk.com
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Date: 15th January 2013

To: (by e-mail)

cusc.team@nationalgrid.com

From: (by e-mail)

zoltan.zavody@renewableuk.com

Dear Sir/Madam,

RenewableUK consultation response

CMP 213 Project TransmiT TNUoS Developments

Summary

RenewableUK welcomes National Grid's consultation on the discussions of the CUSC Working Group. Our overall thinking is as follows:

- **The process and the content of proposals should be considered in the context of the original rationale for the review of transmission charging, namely to facilitate the timely move to a low-carbon energy sector.**
- **There is a need for an ongoing and open assessment of the impact of proposals before decisions are made, not least to avoid unintended consequences.**
- **The work should aim for an implementation date of 1st April 2014, in recognition of the need for a timely outcome that facilitates achievement of the 2020 renewables target and allows congruence with the development of European policy on charging.**
- **We particularly support exploration of a year-round load factor with no peak security; and of the inclusion of 100% HVDC converter costs in the residual.**
- **There is a need for close linkage between this work and work to develop a Government support scheme for island renewables.**

Introduction: RenewableUK, The Work Group Consultation and Rationale

RenewableUK is the trade and professional body for the UK wind and marine renewables industries. Formed in 1978, and with over 660 corporate members, RenewableUK is the leading renewable energy trade association in the UK, representing the large majority of the UK's wind, wave, and tidal energy companies. The association's response aims to represent these industries, aided by the expertise and knowledge of our members.

RenewableUK represents developers from across the UK, from the south of England to the north of Scotland and the Scottish islands, all of whom may be affected differently by various proposals for transmission charging. RenewableUK's vision is of renewable energy playing a leading role in powering the UK's homes and businesses. As such, this response aims to reflect what best serves the long-term deployment of renewable generation as a whole.

Our interest aligns with the original objective of Project TransmiT, namely: "to ensure that arrangements are in place that facilitate the timely move to a low carbon energy sector, whilst continuing to provide safe, secure, high quality network services at value for money to existing and future customers."

While the CUSC Working Group is obliged to assess modification proposals against CUSC criteria, Ofgem states that its direction should be read in the context of the original reasons for the TransmiT SCR. As such, we believe there is validity in referring to these when assessing which proposals to pursue. In particular, proposals should be considered in terms of their compatibility both with a timely move to a low carbon energy sector, and with Ofgem's statutory duty to protect the interests of both current and future customers.

Since 2020 is the legally binding target for renewables deployment, the timeliness of an outcome to the CUSC WG process should be assessed in the context of helping to achieve this target. The original discussions were also concerned with congruence with, and leverage across to, the evolving European charging debate. This opportunity should not be missed by an overly protracted process that, if it runs long enough, would eventually be overtaken by decisions in Europe.

Our response is structured according to the question categories in the consultation, but we take the questions on implementation and transition first, as these are crucial to the framework for the decision making process.

The Proposed Original and Applicable CUSC Objectives

We believe the proposed Original better facilitates the Applicable CUSC objectives on two counts: a) the promotion of competition; and b) cost-reflectivity. These apply to greater or lesser extent to all three areas under investigation, as follows:

On sharing, renewables and in particular wind generators do in general share assets. Recognising this sharing therefore opens up the generation market to more (renewable) generation; and reflects more accurately the costs of transmission. The Original balances the relevant factors of transparency, accuracy, and certainty.

On HVDC, we welcome the proposal to consider HVDC costs but believe this technology should be placed on an equal footing with AC, thereby opening up competition amongst generators that might more easily connect through HVDC; and promoting cost-reflectivity by considering the component costs and benefits of HVDC.

On island charging, the facilitation of generation on the islands allows more entrants into the generation market, particularly in these remote areas. The cost-reflectivity assessment is less clear, and we believe this should be balanced by the need for a stable and predictable charging regime.

In summary, RenewableUK supports the consideration of all three areas addressed in the Original. This is not to say at this stage that all the solutions proposed in the Original, and their combination, are the most effective, and we discuss some of the issues further in our response below, including the need for an ongoing assessment of impacts.

Questions 16-17: Implementation and Transition

Our chief concern is that it is very difficult to understand the impact of the proposals on the generation sector, with particular focus on the renewables industry. While it is important to understand principles relating to transmission charging, CUSC parties are also concerned about the impact on individual projects, and then the impact across both current and future generation. Such issues will be addressed and evidence provided as part of a final Impact Assessment, but this will be after a decision has been made on the proposal(s) to take forward. As such, in terms of how the CUSC process works, opportunities for consultation and an ability to input into the working group's discussions will be limited. Within our sector there is a concern that there may be a range of unintended consequences that then need to be addressed.

RenewableUK's position is necessarily to support proposals that facilitate the accommodation of renewable generation on the system, consistent with the original aims of TransmiT. It therefore needs to be possible to assess the proposals against this criterion.

Furthermore, a criterion for CUSC methodology is that it "facilitates effective competition in the generation and supply of electricity." Competition is best served by transparency and simplicity, whereby generators understand and can respond to price signals.

For these reasons, we support ongoing and open assessment of the impact of the CUSC WG proposals at an early stage and far ahead of the eventual regulatory impact assessment, in order for an informed assessment to be possible. We would urge National Grid and the Working Group to look at options for active and open communication with wider industry, including use of the NG website to include updates of progress, as well as provision of more stakeholder discussion days (such as those held in December 2012) prior to the finish of the Working Group deliberations.

Balanced against this, our other chief concern is that the process will be further delayed. The Significant Code Review report that led to Ofgem's Direction "urge[d] industry to expedite this process and submit a final CUSC amendment report … in a timely manner to ensure benefits are realised as quickly as possible." It also pointed out that the standard CUSC process takes around six months to complete. Protracted delays could eventually come up against the commencement of European legislation from 2014 onwards, and arguments that there is no longer any point in implementing Improved ICRP. Finally, with extensive Round 3 offshore development from around 2017 onwards, it is important that there be a period of charging stability some time before this.

We understand that there are tensions between calling for wider industry engagement and maintaining a strict timetable. However, we wish to emphasise that we are keen that the work should aim for the implementation date of 1st April 2014, and arguments for “further investigation” should not undermine this. We would consider supporting the Working Group, and subsequently, the CUSC Panel, being able to recommend a shorter than usual notice period for implementation, with opt-outs provided to existing generators so that they can manage the risks of transition to a revised methodology.

Questions 1-5: Sharing

We support sharing of some description. Wind generators do in general share assets without this being factored into the charging regime, and this means they have been and are being overcharged. There are many potential solutions, none perfect, but change is needed or wind will continue to be disadvantaged. We believe the calculation methods that warrant exploration are methods iii-v.[1] We do not see how methods i and ii would be compatible with the aims of this work.

We support further consideration of the Original proposal for sharing. The introduction of a peak security tariff may have vastly different consequences for renewable generators in the north and south, and this needs exploration. The impact of not recognising renewables’ contribution to peak demand in negative charging zones results in renewables projects being worse off than conventional generators under IICRP because they no longer benefit from the from the negative peak demand tariff. The Redpoint analysis commissioned by Ofgem also shows significant additional costs to renewable projects in England and Wales where year-round tariffs increase under IICRP compared to the status quo.

We also support a further exploration of the option to use the existing single background Transport model but with charges based on annual average load factor not capacity. In other words, sharing would be based on the total load factor rather than the load factor applied only to the year-round element. Further discussion is needed on how this load factor would be calculated. We understand this option is covered by the existing proposals for Alternatives,[2] otherwise RenewableUK would propose it formally.

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[1] Table 4, page 10.

Questions 6-9: HVDC Circuits

We support the exploration of an Alternative that includes 100% of HVDC converter costs in the residual in the same manner as AC substations.[3] Decisions should not have different outcomes for generators just because different grid technology is used, if the overall cost and benefit to the system are the same. While we understand that the Working Group has sought to understand the similarities and differences between AC and HVDC, we would stress an additional element, which relates to transparency and predictability of charging. While the methodology seeks to apportion the costs of transmission, and the overall cost burden will not be affected by changes to the methodology, different treatment of elements such as substations and converters will impact on generators. Thus decisions taken by Transmission Operators to develop infrastructure using HVDC rather than AC will lead to increasing costs (compared to the AC alternative) for certain generators. This does not seem proportionate or equitable treatment of one group of generators in comparison to another. This would distort competition, and is also likely to disadvantage a large proportion of low-carbon development.

Questions 10-15: Island Connections

We support the need for a support scheme that facilitates the deployment of low carbon energy in the islands. We support the consideration of sharing on the islands. We note, however, that this will be insufficient by itself to remove barriers to connection in the islands. The UK Government is working separately on this issue, but there needs to be close linkage between the two programmes of work. As this process is led by the UK Government, there is a need for the Working Group and CUSC Panel at least to understand the timing of this parallel process, as well as likely options under discussion by public bodies for supporting island generation. We would urge the Working Group to invite a relevant official to attend and present to the Working Group, and vice versa.

It is important that the CUSC process not be bogged down by proposals for a specific issue such as islands charging. However, even as support schemes are discussed, some form of predictable charging methodology is needed for sub-sea cables to the islands. In its deliberations we would urge the Group to take into account

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[2] Item iii, Table 13, page 32.

transparency and predictability as an important component of charges for island based generation. Clearly transmission charges for island generation will be higher. It is therefore very important that the charging base is not volatile and is transparent, as ability of such generators to absorb additional costs (e.g. future transmission charging increases) may be very limited.

Question 18: Governance

We do not wish to raise any new Alternatives, but would particularly like to express our support for further exploration of a year-round load factor with no peak security; and of the inclusion of 100% HVDC converter costs in the residual. We understand this option is covered by the existing proposals for Alternatives,[4] otherwise RenewableUK would propose it formally.

We trust this submission is helpful, and we look forward to working with you towards a timely and transparent outcome.

Yours faithfully,

Zoltan Zavody
Grid Policy Team

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[3] Page 105 a) i).
[4] Item iii, Table 13, page 32.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	*Gaynor Hartnell ghartnell@r-e-a.net 020 7925 3578*
Company Name:	*Renewable Energy Association*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The proposed methodology is an improvement on the current methodology given the revisions to the SQSS that have been implemented that recognise the different characteristics of different types of generator and the resultant different amounts of transmission that each justify investing in. Where we prefer one of the options to the original in any area we mention this in the detailed comments below.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	We think that overall the original does better facilitate the applicable CUSC Objectives compared to the status quo. In particular: In terms of facilitating effective competition the proposal is better than the status quo as recognising the different costs imposed on the transmission system by different types of generator and charging them accordingly it allows fairer competition between generators of different types. The same reasoning applies to objective b better reflecting the costs that are incurred by the transmission licensees. Objective c is better met as the current methodology makes no provision at all for taking account of the cost of dc circuits that run in parallel with the ac network. *For reference, the Applicable CUSC Objectives for the Use of*

	System Charging Methodology 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.*
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	Yes we think that on the whole a date of April 2014 would be appropriate for implementation.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	There does not appear to have been much consideration in the section proceeding this section into the issue of charging for local circuits where there may or may not be diverse types of generation using these circuits. We are aware that the section of the SQSS dealing with the connection of generation is under review and it may be best to revisit issues associated with the sharing of local circuits after this has been completed. In terms of charging for the use of the MITS the group has clearly spent a considerable effort looking at the effect of the variation in generator types on sharing of transmission. Whilst there are undoubtedly other options that could be considered we do not have any specific alternatives that we would advocate.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	We think that the Workgroup has reviewed a sufficient number of options in sufficient depth and we would not advocate further analysis. On balance whilst we feel that although there is much merit in using the fixed load factors that are used in the SQSS, we are persuaded that using the actual five year historic load factors also has merit.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No. Our view is that this a very simple matter – as TNUoS charges are meant to be reflective of the cost of building transmission assets, the peak Security element for intermittent generation of any type should be indexed to whatever is used in the SQSS.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	The Workgroup has certainly considered a large variety of options for the sharing element of the proposal and whilst there are certainly others that have not been considered we do not advocate considering any other one. We note the attention to differences between how the system is planned and how ICRP calculates charges and recognise that this is a weak point of ICRP. If however one is sticking to the ICRP philosophy i.e. that each incremental MW flowing should be charged as an extra MW of capacity then allocating costs between the peak security and year round flows on the basis of the relative flow in each case is more consistent with this than defining each circuit as reinforcement driven by either one or the other case. ICRP assumes that an extra MW flow demands an extra MW of investment and so this is the case for both the peak demand and the year round flows – each circuit should therefore be apportioned between these cases, if consistency with the ICRP philosophy is to be maintained.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	As a general rule the charging methodology should follow the system planning philosophy as far as possible. With a couple of exceptions noted above (and leaving aside the issue of how cost reflective the basic ICRP methodology is) the proposed methodology does that.

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	There may be possible other options but we do not advocate consideration of any specific further ones.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	As above, whilst there are other methodologies we do not advocate consideration of any further ones.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We do not wish the workgroup to consider any specific further options.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	We think that the original proposal is satisfactory although can see merit in reducing the cost of hvdc links that parallel the ac network by the cost of a quadrature booster that would give a similar degree of controllability for so long as the cost of quadrature boosters are not included in the locational element of TNUoS charges.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	There are no doubt other options but we do not wish to promote them. We think that a local / wider split should be maintained on islands whilst it is being maintained on the rest of the system. As stated earlier the issue of sharing on local circuits should follow from the approach in the SQSS.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Yes. We would advocate dividing the circuit length by 1.8 where the island substation is part of the MITs but it only enjoys essentially a single circuit connection to the mainland.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Yes.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	Yes. Our view is that anticipatory changes would have to apply system wide and anticipate a MITs node becoming a local one as well as vice versa. In general we feel that such an arrangement is likely to be problematic.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We do not have any other proposals or options that we would like to be considered.
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	In general islands should be treated like the rest of the system with the reduction in length of a connection to the mainland by 1.8 where it is a single link. Sharing proposals for local circuits should follow what is laid down in the SQSS.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We think that implementation should be in April 2014 if a final decision is made by Ofgem by the end of September 2013, otherwise from April 2015 (assuming a final decision by the end of September 2014).

Q	Question	Response
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	Our view is that following the Ofgem decision generators should have up to 20 working days to give notice to reduce their TECs from the time when the new charging methodology is to be introduced. For example if Ofgem decides on 15th September 2013 that the new methodology should be introduced on 1st April 2014 generators should have 20 working days from 15th September 2013 to make any adjustments to their TECs post 1st April 2014 without penalty.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No *If yes, please complete a Workgroup Consultation Alternative Request form, available on National Grid's website, and return to the above email address with your completed Workgroup Consultation response proforma.*
Do you have any other comments?		No.

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National Grid
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Our Ref: EN01-003502

15 January 2013

Dear CUSC Team,

Re: RES UK&I Response to CMP213 Workgroup Consultation

Renewable Energy Systems (RES) welcomes the opportunity to respond to the “CMP213 Project TransmiT TNUoS Developments” workgroup consultation document published 07 December 2012 (“the Workgroup Consultation”). As a workgroup member, RES has contributed to discussions that have given rise to the progress to date as outlined in the Workgroup Consultation and the views set out below should reflect those contributions. RES is comfortable that the Workgroup Consultation is a fair reflection of the material considered and the key points of debate.

Sharing

Q1: Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?

In light of the implied guidelines set by the preceding work conducted under Project TransmiT and by the Ofgem SCR direction, RES considers that the Workgroup has considered as broad a range of geographical charging structures as could reasonably be expected. RES notes the comment on paragraph 4.61 which states that “*The proposer currently believes that the simplicity of a simple generator’s annual load factor based approach outweighs any cost reflectivity benefits that a more complex approach taking into account generation plant diversity could bring*”. In light of the evidence considered and debate completed to date, RES is in agreement with this statement.

Q2: Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.

RES agrees that the Workgroup has been thorough in its consideration of options for methodologies of calculation of ALF. Taking into account the intended purpose of ALF, i.e. an adjustment to reflect long term network sharing, RES considers, at this stage, that the methodology based on five years of historical output, as included within the original proposal, represents the most appropriate way forward.

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Q3: On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?

RES would not seek to add views in addition to those set out in the consultation. RES would support the approach outlined in the original proposal.

Q4: Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the sharing aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

RES considers that the working group has cast its net suitably wide in considering sharing options and would not, at this stage, propose any additional options.

Q5: What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?

Throughout the Project TransmiT process, RES has supported a move away from purely capacity based charging of TNUoS for generators on the grounds that it is not reflective of transmission owner investment practices nor of actual usage of transmission system assets. RES therefore welcomes the debate around an extensive range of alternative approaches to generator TNUoS charging that better reflect actual development and usage characteristics thereby arriving at a more appropriately targeted Wider TNUoS charge. Going forward, RES is keen to see how sharing options can be refined into potential methodologies which represent an appropriate balance between cost reflectivity, simplicity, transparency and stability. As noted in our response to Q1, at this stage, RES considers the approach to sharing proposed in the original to represent the optimum balance between these factors.

HVDC Circuits

Q6: Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.

RES considers that the workgroup has been thorough in considering possible methodologies for calculation of HVDC expansion factors but is of the view that there is further debate to be progressed in order to reach an appropriately considered conclusion. RES does not agree with the proposal to include the cost of the HVDC converter station in the HVDC expansion factor on the grounds that it would bring about discriminatory treatment against generators connected behind an HVDC link relative to generators not in such a position. RES considers that the arguments raised in relation to AC equivalence and also in relation to equivalence with treatment of onshore fixed plant items such as quadrature boosters and substations substantiate this position. However, more fundamental is the argument that it seems unreasonable and discriminatory to burden certain generators connected behind HVDC circuits with a significantly higher wider TNUoS charge as a result of a TO decision on technology type, a decision that is presumably taken on grounds of transmission system economy and efficiency rather than generator preference.

Q7: Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?

RES is content that the Workgroup has considered an appropriate range of options for modelling of HVDC circuits in the DC load flow model. At this stage, RES would support a methodology for calculation of equivalent impedance using the flows across the average of all boundaries bypassed by the HVDC circuit (as set down in the original) because it represents a more complete reflection of the benefit provided by that HVDC circuit relative to the single most constrained boundary approach discussed in the workgroup.

> *Q8: Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the HVDC circuit aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?*

RES considers that the workgroup has adequately considered options in relation to HVDC circuit operational cost and security.

> *Q9: What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?*

RES would not, at this stage, wish to add any points over and above those points raised in response to Questions 6, 7 and 8.

Island Connections

> *Q10: Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?*

RES notes the extensive review of issues associated with the current definition of MITS GSPs and local circuits that has been conducted by the group and would not propose additional areas of investigation.

> *Q11: Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?*

RES would not propose further alternatives in relation to security factor at this stage.

> *Q12: Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.*

RES would not propose further alternatives at this stage but would reiterate its support for recovery of the cost of HVDC converter stations through the residual charge rather than through the expansion factor as proposed in the original.

> *Q13: Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.*

RES considers that the Workgroup has adequately considered the issue of anticipatory application of the MITS definition to island nodes and would not propose further issues to be considered at this stage.

Q14: Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

RES would not propose further Island alternatives at this stage.

Q15: What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?

RES agrees with the overall thrust of the discussions in the Workgroup, namely that it is difficult to justify changes to the TNUoS charging methodology in a manner consistent with CUSC relevant objectives for the specific circumstances of Islands.

Implementation and Transition

Q16: The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.

At this stage, RES would support option 2 "implementation from 1st April 2014" as the optimum balance between timely implementation and opportunity for due consideration.

Q17: The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.

RES would not propose a specific transitional reduced notice period for TEC reduction or termination at this stage and considers that the requirement for one off arrangements will become clearer once the materiality of the proposed options becomes clearer.

Governance

Q18: Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?

RES would not wish to propose a specific Workgroup Consultation Alternative Request.

Yours sincerely,

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Swindon, 15/01/2013

CMP213 Workgroup Consultation - RWE Response

Dear Cusc Team

We welcome the opportunity to comment on the CMP213 Workgroup Report. This consultation represents an important stage in the evolution of the GB transmission charging regime.

We note the considerable work undertaken by the working group. This includes the development of a large number options and variables which may result in alternatives that better meet the CUSC objectives. However, we have a number of concerns on progress to date including the following:

- The process completed by the Working Group to date is flawed in that group has not fulfilled the terms of reference as set out by the CUSC Panel on 9th July 2012 particularly with respect to paragraph 5 (k) in the scope of work with respect to "consider and undertake appropriate economic analysis including the impact on current and future customers on a national and regional basis". The Working Group Report does not include any assessment of the impact on the proposal on customers whether existing or future customers.
- Further work is required on the original modification proposal to clarify the arrangements and the potential options that remain in or out of scope. For example, there are a wide range of different approaches towards the issue of sharing particularly with respect to the assessment of load factor including the potential development of a "diversity" factor.
- It is very difficult to evaluate objectively the potential options from the information presented in the report. This reflects the absence of both qualitative and quantitative criteria to determine the relative merits of the options and detailed information in the form of evolved tariffs and the potential impact on generators and customers. This makes it impossible to determine whether competing options better meet the CUSC objectives.
- Substantive work is required both to define a small number of alternatives and to provide the detailed analysis that would enable market participants to form a view on the relative merits of the proposals. It is essential that such work is subject to further industry consultation prior to consideration by the CUSC Panel.

- We do not believe that it is appropriate for an impact assessment to be undertaken during the Code Administrator's Report phase under the CUSC modification process. We fail to see how market participants and the CUSC Panel can possible come to a view on the proposals against the relevant CUSC Objectives without such an assessment during the initial working group phase.

In the absence of any detailed assessment, we can only rely on work conducted outside the modification workgroup to provide our views on the proposals. Work by Redpoint as part of the Ofgem Significant Code Review has already indicated the negative customer welfare impact of the "improved" ICRP methodology[1] particularly in relation to constraint costs and transmission investment. Further work from NERA[2] indicates that "improved" ICRP will significantly impact on customer welfare through effects on the marginal costs of electricity generation.

Whilst neither report provides a definitive view of the emerging CMP213 proposals in the Workgroup Report, we can only conclude that "improved" ICRP as set out in the original proposal will not better meet the CUSC Use of System Charging Objectives[3]. In particular:

- The proposal fails to facilitate the competition in the electricity market (CUSC UoS Charging Objective (a)) given the effects on the marginal costs of generation in the GB market and the lack of cost reflectivity when compared with the current arrangements;
- The relationship between Incremental constraints costs and Annual Load factor has not been demonstrated across the GB system for the current plant disposition under CMP213 and furthermore this relationship does not hold for future years as demonstrated in the report by Bath University[4] The CMP213 proposal with respect to sharing does not, therefore, better meet CUSC UoS Charging Objective (b);
- The locational signals inherent within the methodology have a detrimental impact on existing high and low load-factor power stations in southern Britain while incentivising the location of new low and high load-factor plant behind constraints. The CMP213 arrangements are not more cost reflective when compared to the current arrangements and do not, therefore better meet CUSC UoS Charging Objective (b); and

[1] Ofgem transmission charging arrangements: Significant Code Review Conclusions, 4th May 2012
[2] NERA Report "Project Transmit- Modelling the Impact of Improved ICRP", 12th October 2012 can be found at http://www.nera.com/67_7953.htm

[3] CUSC Use of System Charging Objectives: (a) that compliance with the connection charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the 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 connection charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses

[4] Op cit

- The arrangements are not compatible with emerging thinking on transmission charging within the European Target Model. Consequently we do not believe that the proposal better meets CUSC UoS Charging Objective (c).

Potential Variant
We believe that in addition to the options under consideration a potential variant should be developed based on a cost reflective forward looking charging methodology for the calculation of generation load factors. The methodology should utilise a forecast of nodal generation that reflects the background (peak and year round) transmission conditions. In effect the model will provide a forward looking assessment of the potential use and sharing of the GB transmission system to enable the calculation transmission charges that reflect the costs of efficiently incurred transmission investment and cost recovery of existing network assets.

The answers the detailed questions in the consultation document are included in the pro forma response submitted separately.

If you wish to discuss any aspect of our response, please do not hesitate to contact me.

Yours sincerely

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CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	*Please insert your name and contact details (phone number or email address) Bill Reed; bill.reed@rwe.com, 01793893835*
Company Name:	*Please insert Company Name* RWE Supply and Trading GmbH, RWE Npower plc, Great Yarmouth Power Ltd, Npower Cogen Trading Ltd, Npower Direct Ltd, Npower Ltd, Npower Northern Ltd, Npower Northern Supply Ltd, Npower Yorkshire Ltd, Npower Yorkshire Supply Ltd, RWE npower renewables, a wholly owned subsidiary of RWE Innogy GmbH
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We note the considerable work undertaken by the Workgroup. This includes the development of a large number of options which may result in alternatives that better meet the CUSC objectives. However we are concerned that since neither the CMP213 original proposal nor any of the alternatives have been properly defined there is no modelling work to examine the effects of these proposals and the impact on the wider electricity market including existing and future customers. Consequently it is very difficult to comment meaningfully on the consultation. In addition, it is difficult to assess whether the theoretical models developed by the Workgroup could lead to inefficient outcomes with major unintended consequences for transmission system development. Given the complexity of this CUSC modification, we believe that industry should be given the chance to comment on defined models, their effects on future tariffs and the market in general, the associated impacts and implementation issues before the final legal drafting consultation takes place. We have a number of concerns on progress to date by the Workgroup including the following: • The process completed by the Workgroup to date is flawed

	in that group has not fulfilled the terms of reference as set out by the CUSC Panel on 9th July 2012 particularly with respect to paragraph 5 (k) in the scope of work with respect to "consider and undertake appropriate economic analysis including the impact on current and future customers on a national and regional basis". The Workgroup Report does not include any assessment of the impact of the proposal on customers whether existing or future customers. • Further work is required on the original modification proposal to clarify the arrangements and the potential options that remain in or out of scope. For example, there are a wide range of different approaches towards the issue of sharing particularly with respect to justification and interpretation of the National Electricity Transmission System Security and Quality of Supply Standards (NETSSQSS) findings and in particular the GSR009 implementation, the assessment of load factor as a proxy for incremental constraint costs, the potential development of a "diversity" factor on a cost reflective basis and the nature of derived historic factors for future transmission charges. • It is very difficult to evaluate objectively the potential options from the information presented in the report. This reflects the absence of both qualitative and quantitative criteria to determine the relative merits of the options and detailed information in the form of evolved tariffs and the potential impact on generators and customers. This makes it impossible to determine whether competing options better meet the CUSC objectives. • Substantive work is required both to define a small number of alternatives and to provide the detailed analysis that would enable market participants to form a view on the relative merits of the proposals. It is essential that such work is subject to further industry consultation prior to consideration by the CUSC Panel. • We do not believe that it is appropriate for an impact assessment to be undertaken during the Code Administrator's Report phase under the CUSC modification process. We do not see how market participants and the CUSC Panel can possibly come to a view on the proposals against the relevant CUSC Objectives without such an assessment during the initial Workgroup phase. In the absence of any detailed assessment, we can only rely on work conducted outside the modification workgroup to provide our views on the proposals. A study by Redpoint as part of the Ofgem Significant Code Review has already indicated the

	negative customer welfare impact of the "improved" ICRP methodology[1] particularly in relation to constraint costs and transmission investment. Further work from NERA[2] indicates that "improved" ICRP will significantly impact on customer welfare through effects on the marginal costs of electricity generation. In addition, the dual background approach to represent approximately the dual criteria approach of the NETSSQSS is flawed, and historic annual load factor alone cannot represent all the factors which determine the level of constraints and where they occur on the GB electricity system[3]. In this context GSR0009 under the NETSSQSS introduced the concept of "dual criteria" when assessing the transmission system capacity based on a demand security criterion whereby peak demand can be met without intermittent generation and an economic criterion that requires sufficient transmission capacity to enable all types of generation to meet varying demand levels based on a cost benefit analysis that reflects an economic and efficient trade-off between constraint costs and transmission investment. This dual criteria approach enables the peak load scenario to be overlaid by the cost benefit analysis to identify economic and efficient transmission investment. However the CMP213 approach based on a "dual background" (peak and year round) rather than the dual criteria approach results in two separate charges which are then integrated into the annual charges. While we recognise that there are important principles related to the alignment of the charging arrangements with the NETSSQSS principles, we do not accept that it follows that the charging arrangements have to adopt the same methodology as the arrangements for the design of the transmission system. We recognise that there is an important trade off between transmission investment and constraints. Under the current arrangements it is clear that the transmission owners will only invest in economic and efficient transmission assets that reflect use of the system. Consequently the TEC-based charges reflect the recovery of the capacity based investments and not the efficiently incurred constraint costs implied through the application of the NETSSQSS. Indeed the fact that the costs of constraints are socialised through BUSUoS demonstrates a divergence between the NETSSQSS and the charging arrangements. Furthermore, the socialisation of BSUoS with respect to the

[1] Ofgem transmission charging arrangements: Significant Code Review Conclusions, 4th May 2012
[2] NERA Report "Project Transmit- Modelling the Impact of Improved ICRP", 12th October 2012, http://www.nera.com/67_7953.htm
[3] Furong Li et al, (Forthcoming), "Year round system congestion costs – Key drivers and key driving conditions", University of Bath

	incremental costs caused by the connect and manage arrangements clearly create a number of issues for the evaluation of CMP213. In particular we believe that CMP213 must take into account an optimised version of transmission investment and explicitly address the issue that the actual network configuration may not be not compliant with the NETSSQSS as a consequence of connect and manage. In addition the charging methodology must also take account of the advanced connection dates for connect and manage generators which give rise to additional early constraint costs. In principal the current charging arrangements reflect the fact that less wider transmission assets are being built for low load factor plant. However the NETSSQSS dual background connection methodology together with connect and manage arrangements already result in incremental constraint costs. CMP213 may lead to further constraints as generators respond to the less cost reflective locational signals. This will result in less economic transmission investment when compared with the current charging methodology. Further consideration is also required of the effect of connect and manage arrangements on exacerbating costs in constrained areas under the "improved" ICRP methodology (as indicated in the Redpoint work[4]). We note that since these costs are already socialised, then any increase in such costs effectively increases the cross subsidy and discriminatory treatment in favour of certain users. Therefore these effects must be quantified and appropriately assessed (particularly in relation to additional state aid considerations).
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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);*

[4] Op Cit

	(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. The large number of options and variables included in the Workgroup document makes it difficult to determine whether the CMP213 original or any options for alternative better meet the relevant CUSC objectives. In particular the lack of a detailed impact assessment suggests that it is difficult to provide any determination in relation to the CUSC objectives. Given information provided elsewhere by Redpoint and the published NERA[5] analysis we believe that the original version of CMP213 may not better meet the CUSC objectives. In particular: • The proposal fails to facilitate the competition in the electricity market (CUSC UoS Charging Objective (a)) given the effects on the marginal costs of generation in the GB market and the lack of cost reflectivity when compared with the current arrangements; • The relationship between Incremental constraints costs and Annual Load factor has not been demonstrated across the GB system for the current plant disposition under CMP213 and furthermore this relationship does not hold for future years as demonstrated in the report by Bath University[6] The CMP213 proposal with respect to sharing does not, therefore, better meet CUSC UoS Charging Objective (b); • The locational signals inherent within the methodology have a detrimental impact on existing high and low load-factor power stations in southern Britain while incentivising the location of new low and high load-factor plant behind constraints. The CMP213 arrangements are not more cost reflective when compared to the current arrangements and do not, therefore better meet CUSC UoS Charging Objective (b); and • The arrangements are not compatible with emerging thinking on transmission charging within the European Target Model. Consequently we do not believe that the proposal better meets CUSC UoS Charging Objective (c).
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We believe that further consideration of the implementation dates is required given the need for the completion of an impact assessment of the original and any potential alternatives by the Workgroup and the likely effects such a change will have on the electricity markets including assessment of lead times for

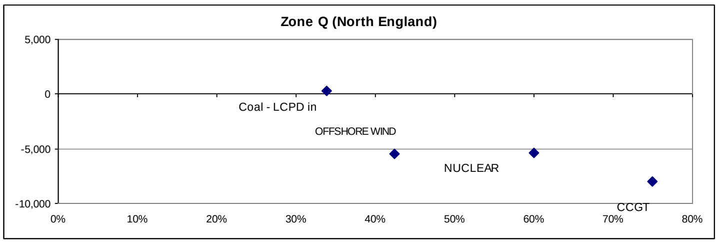
[5] Op Cit
[6] Op cit

	electricity power purchase arrangements and the proposed capacity mechanism The impact on existing and previously sanctioned plant should also be taken into account. Transitional arrangements (including the role of grandfathering) should be considered as a means of mitigating regulatory risk. If this is not considered, it may become difficult to obtain financing in future. We believe that this is a particular issue for renewables projects given the large number of projects in development

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	We do not believe the that workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits. The work undertaken by the group with respect to options for the charging structures in areas dominated by one type of generation provides an important insight into the cost reflectivity of the sharing arrangements outlined under CMP213. What has become clear is that some areas of the transmission system are dominated by certain generation types. This means that in considering the cost reflectivity, any sharing arrangements must take into all account the different characteristics of generators connected to the GB transmission system in these areas. These characteristics are related to the generators ability to self dispatch when the market price is favourable, which correlates with demand on the entire system, and also the Bid and Offer prices submitted in the market. Specifically, in some exporting areas, the bid price is one of the main driving factors for constraint costs for some specific plant types. This means that if the transmission system is constrained at times when dominated by intermittent generation output, then the constraint costs are high. It is important to note that the adverse effect of this type of generation on constraint costs is not dependent on its yearly out-turn Annual Load Factor, but on its correlation with other generators in the same area. The diversity of zones dominated by different types of generators significantly increases the complexity of the suggested arrangements when compared to the uniform approach to entry capacity under the current ICRP methodology. We believe that this complexity is reflected in the range and extent of the different approaches towards sharing options considered by the Workgroup, some of which may result in alternatives. Our preferences is to synthesise the options for sharing into a variant based on a forward looking cost reflective load factor assessment that utilises representative forecast of generation output under the relevant transmission network configurations (peak and year round). Such an approach would enable the charging arrangements to have due regard to future changes in generation and the transmission network.

Q	Question	Response
		The essence of this variant would be to calculate a factor which effectively multiplies the signals derived for a "year-round" scenario to account for diversity and other factors. Note that we are only proposing this as a variant rather than an alternative to CMP213 since the original proposal must use just two backgrounds, (peak and year round).
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated? Are there any areas that you think may need further development? If so, please specify along with an associated justification.	The workgroup has not sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. We note the comprehensive consideration of load factors across transmission boundaries and note that the relationship between constraint costs and load factor may not be a simple linear relation (see for example, Figure 30 and 31 in the Workgroup consultation document). This is illustrated in the graph below for the North of England boundary.  Further work is, therefore required to consider the relationship between constraint costs and load factor. In particular consideration should be given to forward looking sharing factors based for example, on the prospective contracted TEC a security constrained dispatch model for the respective background scenario and representative relationships between load factor and constraints. We believe that such an approach would be capable of delivering more cost reflective tariffs than any approach based on historic analysis.

Q	Question	Response
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	We believe that intermittent generation should be exposed to a Peak Security element of the tariff where it is cost reflective to do so. In this context the Workgroup should investigate the definition of peak security. The key question is whether it means one single half hour when the yearly demand is at its absolute peak, or a time period of the year when the daily peak demand is expected to be within say 95% of the out-turn absolute peak demand. This is important, since at the absolute peak demand level, generation availability is usually high enabling the System Operator to optimise the flows on the network and accommodate high levels of intermittent output, and in particular in importing areas. If “peak” means a period from say November to February, then it is clear that intermittent will be generating at peak and will contribute to peak security. In addition if the penetration of intermittent types of very high, and at diverse locations on and off shore of the UK, then it can be expected to be generating significant volumes at all times. It is appropriate for intermittent generation to be exposed to a Peak Security tariff where such generation is capable of contribution to generation output at the peak. In this context it is important that conventional thermal intermittent generation such as OCGTs and hydro schemes are considered alongside the peak contribution from renewable technologies such as wind. Stochastic approaches should be considered by the workgroup to capture the probability of intermittent renewable technologies contributing to meeting peak demand.

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We do not believe that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal. While we note the considerable work on sharing undertaken by the workgroup a wide range of potential options remain under consideration. It would be helpful if the potential sharing options are organised into a coherent and workable set of proposals that appropriately reflect on users the costs associated with use of the transmission system. In this context we do not believe that the sharing arrangements based on the dual background in the original proposal are cost reflective, particularly in relation to the use of historic load factors. We are more supportive of potential options that reflect prospective "diversity" and allow for capacity-based charging arrangements to reflect the transmission benefits of locating power stations in certain areas of the GB transmission system. In the context of diversity, we believe that a potential variant based on a forecast of expected output from generation and demand nodes across the network and a model that considers the prospective outcome of load flow conditions across the network in an optimised least cost approach should be developed to reflect sharing across transmission boundaries. The model would be based on the contracted TEC for each power station, the demand capacities and the expected state of the transmission network. A set of load factors would be derived for each node based on an optimised least cost dispatch model on an unconstrained basis (the "unconstrained schedule"). The model would then be rerun to identify the cost of constraints (the "constrained schedule"). The forecast costs of constraints together with the nodal costs of the transmission network would provide the basis for calculating the Transmission Use of System tariffs for the following year. We also believe that the potential variant should enable the calculation of long term tariffs (across multiple years). Such an approach would enable parties to efficiently and effectively manage the risks associated with use of system charges and would facilitate the introduction of other market reforms (such as a capacity mechanism).

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	The current TEC-based approach towards transmission charging is the most cost reflective approach to the impact of different generators on incremental network costs. Under this methodology all generators are treated on a non discriminatory basis and all generators are capable of accessing the transmission network up to the level of their TEC. If it is not possible to devise a an appropriate cost reflective methodology that reflects capacity sharing then the current capacity based arrangements are more cost reflective. It is, however, appropriate for the NETSSQSS to take into account generator characteristics in the design of the network. This results in economic and efficient transmission investment.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We note the potential options associated with the treatment of HVDC links. We believe that it is essential that the principal that the beneficiary pays for the investment should be established in relation to such assets. This implies that generators in northern Scotland should contribute a cost reflective fair share in relation to the charges for these transmission investments. We note that this may result in higher charges for generation in Scotland reflecting the fact that such users will benefit from reduced constraint costs, have more reliable access to the GB electricity market and only pay for economic and efficient investment.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	We believe that the workgroup has satisfactorily considered the all the options and potential alternatives for the treatment of an HVDC network as part of the GB transmission system.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We believe that the workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal.

Q	Question	Response
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The best way to incorporate HVDC circuits that parallel the AC network in the TNUoS charging methodology is to consider HVDC circuits as an equivalent AC circuit with an equivalent Impedance and a specific Expansion Factor for individual HVDC circuits. The calculation of the impedance is important and should be derived from the same principles which are used to justify the investment in the HVDC circuit; this should be based on the planned flows expected on each HVDC circuit where HVDC can be justified as the lowest cost option for transmission investment. The Expansion Factor should be calculated from the total cost of the HVDC scheme without the arbitrary definition of sub-station equipment to dilute the costs of the whole HVDC system. If an element of the converter costs can be justified by the System Operator as providing a benefit in operating the network over and above that offered by the usual AC system, then that element of the costs can be removed from the converter costs with a clear justification that the System Operator will gain efficiencies in voltage control, losses on the whole network. We would expect this to be reflected in an explicit reduction in System Operator operating costs.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	While we understand the arguments in favour of encouraging the development of renewable schemes in areas of high renewable potential such as the islands, we do not accept that the GB transmission charging methodology should be used as a basis for providing additional subsidy for such schemes. If a subsidy is given through transmission charges (implicitly or explicitly) it may lead to further system inefficiencies and additional constraint costs which may make it more difficult to obtain secure connections for new projects in these areas. This will inevitably lead to economically inefficient investments and increased overall cost. Consequently it is essential that the beneficiary should pay for the required transmission investment (both local and wider under the charging arrangements). We believe that explicit renewable support arrangements, particularly the proposed CFD should remain the basis for support for low carbon technologies.

Q	Question	Response
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	We believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy.
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	We consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	We consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	We do not believe that the case has been made in the workgroup consultation for any change to the treatment of the island connections in the TNUoS charging methodology. We note that the links to the islands are initiated by new generation projects and in this case we believe that the beneficiary should pay for these links on a cost reflective basis. There is a limited case for sharing with demand where this may increase security of supply. However, the majority of these links should be regarded as local links with the relevant TNUoS charges calculated on the same basis as other local charges.

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	We believe that further consideration of the implementation dates is required given the need for the completion of an impact assessment of the original and any potential alternatives by the Workgroup and the likely effects such a change will have on the electricity markets including assessment of lead times for electricity power purchase arrangements and the proposed capacity mechanism. The impact on existing plant should be carefully considered. Financial investment decisions were based on the best available information at the time that those decisions were made. If transmission costs change substantially as a result of a significant change to the existing methodology this is a change that generators could not have anticipated. Consequently transitional arrangements are appropriate for existing generators. CMP213 may add considerable risk to the sector and will make it more difficult to make the case for funding for projects in future given the amount of perceived exposure to regulatory risk and even more so if transitional arrangements are not included.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	We support a transitional approach towards implementation of CMP213. Our preference is for a suitable lead time that would enable users to anticipate the proposed changes in their commercial arrangements This should as a minimum be two years from the start of the charging year (1st April) after the year in which an Ofgem decision is made to be consistent with hedging timescales in the electricity market. In addition transitional arrangements are required that enables existing generators to effectively manage the risks associated with the change over a number of years. This could be a gradual introduction of the new charges for qualifying generators over a minimum of five years after the implementation date.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	*If yes, please complete a Workgroup Consultation Alternative Request form, available on National Grid's website, and return to the above email address with your completed Workgroup Consultation response proforma.*
Do you have any other comments?		As noted in our answer to question 5, we believe that in addition to the options under consideration a potential variant should be developed with network sharing derived from a cost reflective forward looking Network Capacity Charging methodology for the calculation of

Q	Question	Response
		generation and demand TNUoS charges. The methodology should be based on an assessment of the background conditions for a prospective a charging year derived from forecast nodal generation and demand conditions for transmission conditions that are representative of the peak and year round background scenarios. In effect the model will provide the marginal prices for efficiently incurred transmission investment and cost recovery of existing network assets under the relevant transmission background. The methodology could include the following elements: • Nodal representation of the transmission system under peak and year round conditions for the relevant charging year including all network reinforcements and new investments planned to be delivered and operational in the relevant year. • An economic model for nodal unconstrained generation and demand. This model would enable an expected pattern of nodal annual load factors to be derived based on least cost dispatch. The economic model would include representation of network conditions under the background network conditions. • Generation data to complete the economic model would be based on the transmission entry capacity and the assumed characteristics of individual power stations connected to the transmission system (including marginal generation costs). Data would be derived from assumed economic and efficient generator output confirmed after consultation with market participants. • A load flow assessment based on the current ICRP methodology carried out for each node in turn under the representation of the background conditions. Incremental network requirements would be identified reflecting the conditions on the network. • An incremental MWkm would be established for each node. This would result in a range of MWkm derived from background conditions. A weighted average incremental MWkm can be derived that represents conditions on the transmission system under the peak and year round conditions. • The incremental MWkm for each scenario would be converted into tariffs. The tariffs would then be combined into the wider tariff.

Q	Question	Response
		It should be noted that under this methodology • The capacity at each generation node could be constrained by the Transmission Access Capacity; • The nature of the reference node for future background conditions should be established. This could be a single reference node. • The methodology may reflect the fact that constraint costs are socialised across all users under BSUoS charges as a result of the connect and manage arrangements. • The methodology should take into account the effects of the connect and manage arrangements on the state of the GB transmission system for each snapshot period (to avoid exaggerating the costs of constraints by including the connect and manage constraint costs in the assessment or understating the amount of transmission investment). A forward looking cost reflective charging methodology would enable the development of long term tariffs that better reflect the locational marginal costs and benefits associated with generation and demand on the GB transmission system. Such an approach would facilitate the development of GB charging arrangements that are consistent with emerging thinking on transmission charging under the European Target Model and with the proposed GB capacity mechanism.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	*James Anderson; james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	ScottishPower believes that the Workgroup has carried out a thorough investigation of the issues raised in Ofgem's SCR Direction and of the supplementary issues raised by the CUSC Panel. We are not aware of any major issues which have not yet been addressed by the Workgroup. However, we would caution the Workgroup against bringing forward an excessive number of Workgroup Alternative Modifications as Users are seeking clarity of direction at as early a date as possible.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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. ScottishPower supports the Original Proposal and believes that it better meets the Applicable CUSC Charging Objectives as follows; Better reflecting the investment costs driven by generators' siting decisions through the Use of System Charging Methodology will improve competition and help better meet Objective (a). Better reflecting the investment costs which generators impose upon the transmission system through their operating pattern (as best reflected in their load factor) improves the cost reflectivity of TNUoS charges and better meets Objective (b). Recognising that National Grid has refined its transmission investment cost benefit analysis methodology (through SQSS GSR009), the Original Proposal takes account of this development in the transmission business and reflects this in the Charging Methodology better meeting Objective (c).
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	ScottishPower supports the proposed implementation approach and would stress the importance of striving to achieve a 1 April 2014 implementation date in order to reduce further uncertainty over future TNUoS charges.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	ScottishPower believes that the Workgroup has not yet had a full opportunity to consider the evidence presented by Heriot-Watt University (4.298 to 4.319) which indicates that even in areas dominated by intermittent generation, the total amount of transmission capacity built economically and efficiently would be less than the total installed generation capacity. Clearly the effects of counter-correlation demonstrated in this work would have to be factored into any alternative proposal in which a Sharing Factor was applied to the tariff components.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	ScottishPower supports the use of an Annualised Load Factor (ALF) as a proxy for all the other economic parameters which determine a generating station's use of the transmission system. We remain concerned, however that the historical methodology proposed for calculating ALF does not take sufficient account of factors which significantly change a generator's future running pattern e.g. environmental legislation, extended outage (planned or unplanned due to breakdown) or other factors. We would support further work on developing a methodology which used Generators' forecast load factors followed by reconciliation post year–end. This methodology would be comparable to that used for suppliers' TNUoS forecast demand volumes which are also reconciled ex-post. Differences between forecast and actual usage values could be charged at 1.5 times the TNUoS rate with any over-recovery either being reallocated to all generation users via the Residual Charge or carried forward in the Kt factor to the following charging year.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	In planning for transmission access under SQSS GSR009, the System Operator assumes a zero contribution towards peak security from intermittent generation. Therefore, ScottishPower supports the majority view of the Workgroup that the Peak Security element of the tariff should not be applied to intermittent generation.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Yes. We believe that the Workgroup has thoroughly considered all relevant options and potential alternatives on the sharing aspect of the modification proposal. As stated in our response to Question 2 we believe that an Annualised Load Factor adequately reflects all the other economic parameters which determine a generator's use of the transmission system.

Q	Question	Response
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	ScottishPower believes that the original proposal achieves the best compromise between cost-reflectivity and additional complexity in reflecting the differential impact of generators into the charging methodology. While the use of a dual background and scaling factors adds a level of complexity to the existing charging model there are considerable benefits in improved cost-reflectivity. These benefits were quantified in the economic analysis prepared by Redpoint on behalf of Ofgem within Project TransmiT. The benefits of adding considerable additional levels of complexity through the use of a Sharing Factor has not yet been demonstrated and we believe that the introduction of this into the methodology would greatly reduce the transparency and predictability of TNUoS tariffs thus making it less practical for developers to make efficient economic decisions.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	We believe that the Workgroup has considered all the relevant options from full inclusion of the HVDC Converter Stations in the expansion factor through partial inclusion to full exclusion. See our response to Question 8 below.
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	We believe that the Workgroup has considered all the relevant options for modelling an HVDC circuit in the Transport Model. See our response to Question 9 below.

Q	Question	Response
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	While ScottishPower has sympathy with the view that the cost elements of HVDC converter stations do not vary according to distance and should not therefore form part of the Expansion Factor, we recognise that they also form an integral part of the HVDC engineering solution. However, to the extent that elements of the HVDC converter station replicate the function of AC components such as substations and Quadrature Boosters which are not currently charged locationally, then equitable treatment dictates that these costs should also be excluded. Unless further cost analysis can be obtained, ScottishPower recommends that the percentage breakdown of HVDC converter costs identified at 5.35 and 5.44 should be used. Avoiding the need to derive a specific percentage split for each HVDC converter station would improve predictability and reduce uncertainty in forecasting TNUoS tariffs.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	The existing DCLF ICRP Transport Model makes use of circuit impedance to calculate circuit flows. On the assumption that it is intended to continue to use the Transport Model, it will be necessary to calculate a notional impedance for the HVDC circuits in order to allocate a proportion of the energy flows to these circuits. Of the methodologies proposed for calculating this notional impedance, calculating the desired flow across ***all*** the transmission boundaries that the HVDC circuit relieves seems to best reflect the economic justification for investment in the HVDC circuit and is our preferred option.
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	ScottishPower believes that the Workgroup has thoroughly explored the options for charging island generation nodes and that an appropriate charging methodology can be developed from the options discussed.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	We believe that where full redundancy is not provided in an island generator’s connection that this should be reflected in the charging methodology whether the connection is deemed to be Local or Wider. We consider that the option of adjusting (dividing by 1.8) the Expansion Factor of the island circuit is an practical method of achieving this.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	Due to their geography, the three proposed island link links will vary greatly in length and perhaps also in the nature and cost of their construction due to seabed conditions. Producing a generic Expansion Factor for radial HVDC links would therefore result in benefits for some island users and dis-benefits to others. ScottishPower supports the use of specific expansion factors which will avoid such anomalies and will provide a more cost-reflective signal to generators.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	There is no precedent for anticipatory application of changes to the transmission network in the charging methodology. The existing methodology does not anticipate the connection of generators or the completion of new transmission circuits and models the network as described at the commencement of the charging year. Anticipatory application of the MITS definition would require safeguards to ensure that the future changes (which would justify such a definition)n actually took place and thus avoid “gaming” by developers who could potentially secure lower charges through making spurious grid connection applications. It would not be practical to recalculate charges retrospectively over a number of charging years should a node fail to meet the MITS definition.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the “island connection” aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	ScottishPower considers that the Workgroup has thoroughly explored the potential options for accommodating island connections within the charging methodology. In its consideration of the various options, the Workgroup has demonstrated the need for consistent application of the same principles to both island and other long radial connections thus avoiding any potentially undue discrimination in treatment.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	We believe that the existing definition of a MITS node should be used to define whether an Island connection is treated as being "Wider" or Local". Expansion Factors for island connections should be calculated consistently with those for HVDC circuits paralleling the onshore transmission network (i.e. a proportion of converter station costs should be excluded). Expansion factors should be specific to each island connection to retain cost-reflectivity. The reduced level of security afforded to island generators should be addressed by adjusting the expansion factor to reflect this. Where island circuits meet the Local definition, and sharing of transmission capacity can clearly be demonstrated by the construction of a lower capacity than the sum of the generators' capacities, this sharing should be reflected in the Local element of the tariff.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	In their Direction of 25 May 2012, the Authority urged industry "to expedite this process and submit a final CUSC modification proposal report, with all the requisite justification and evidence, in a timely manner ***to ensure benefits are realised as quickly as possible***". ScottishPower therefore believes that implementation should be in as short a timescale as practicable in order to realise those benefits and therefore supports Option (2) April 2014. Although conscious of the problems introduced by a mid-year tariff changes, should this date not be achievable, we would support Option (3) mid-year 2014/15.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	ScottishPower would not support a transitional approach to implementation. In a similar way to the changes to TNUoS charging parameters being introduced at the start of a new Price Control period (see CMP214), National Grid have provided indicative tariffs and information on the potential direction of tariffs which Users should have been able to take account of in making their economic decisions. Please see our response to Question 16 above.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Team
National Grid
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA
Sent via email to cusc.team@national grid.com

15 January 2013

Dear CUSC Team

Response to CMP213 Workgroup Consultation

Scottish Renewables is the representative body for the renewable energy industry in Scotland, with over 320 member organisations. This industry is playing a crucial role in the Scottish and UK Government's efforts to tackle climate change and increase our energy security, and must continue to do so in order to cut greenhouse gas emissions by 80% by 2050.

Scottish Renewables develops policy and canvasses expert views through dedicated working groups. This consultation response has been developed from comments and recommendations made by members of the Scottish Renewables Grid Workgroup, checked and augmented by views from the wider Scottish Renewables membership.

As you will know Scottish Renewables, with Highlands and Islands Enterprise, has been involved in the Project TransmiT Working Group through its representative on the CMP213 workgroup. This response is therefore reflective of additional input and comments from those not intimately involved in this process. That is, we have not sought to repeat views already expressed through the Working Group process.

We wish to take this opportunity to acknowledge and express thanks for the enormous amount of work undertaken by the CMP213 workgroup on what continues to be a challenging and contentious issue for industry.

I trust that you find our comments helpful, and if you require clarification on any of the points made in the attached response, please don't hesitate to contact me.

Yours sincerely

Catherine Birkbeck
Senior Policy Manager – Grid & Markets

Response to CMP213 Workgroup Consultation

Process and timescales

There is a widespread view that whilst the consultation itself is very detailed, there is not yet enough information to understand the implications and “bottom line” of the potentially likely main Alternatives.

Members were concerned that this is the last chance to comment on options, before options are very clearly defined. The general feeling was that the Working Group is not really at the Working Group consultation stage, but that time pressures have forced the consultation out.

During discussion at the Scottish Renewables Grid Workgroup, there were mixed views on how to address this. Some felt that additional consultation at a later stage would add delay that, on balance, would compromise implementation times and further delay the benefits of the Modification. Others felt that improving the quality of the Modification through further consultation could be worth some reasonable delay.

The group also therefore debated whether there might be a compromise where the process is not delayed, but where there remains further opportunity to influence the shape of the Alternatives in light of information on impacts. In that vein, Scottish Renewables would like the Working Group to consider release of preliminary impact assessment results, or at least indicative modelled tariffs, prior to submitting the Working Group report to the CUSC Panel. This could be facilitated through TCMF or via some other informal route where the information is released to industry. This would facilitate gathering wider views into the Working Group which itself would in any event be refining and finalising proposals in view of modelling work.

Further specific comments on each part of the proposals are as follows:

Sharing and diversity

Concerns described above were most acute around the Diversity options being debated for potential Alternatives. It seems almost certain that there will be a Diversity Alternative or Alternatives, but there is still a body of work to complete before it is possible to address questions such as: the direction of travel for tariffs; volatility implications when plant enter and leave a zone and other outcomes. More specifically, we accept that it can be demonstrated that relationships between load factor and constraint costs aren’t uniform across the network, but we do not accept that the proposed solutions address this. They seek to take account of bid prices but do so in a way that themselves require some heroic assumptions and have not yet been tested. Therefore we are not convinced that there is an improvement in accuracy, whilst there is definitely an increase in complexity.

We are conscious that these comments also hold for island sharing proposals brought forward by EMEC, Highlands and Islands and ourselves, in so far as the proposals are not fully developed. We therefore understand the pressures the workgroup is under and the balance between consulting before or after something is fully developed. Scottish Renewables would welcome the opportunity to provide further industry comment as and when these proposals take more concrete shape.

Island expansion factors

As you will know, many industry participants remain concerned about the level of potential charges for the Scottish islands, and the targeting of cost risks onto developers (e.g. the assumption that generators need to absorb cost increases after they have placed user commitment and proceeded to build their project, as evidenced by recent events in the Western Isles).

Island developers also feel at a disadvantage to mainland developers where some cost categories are more readily fed into the residual component, but where there is a reluctance to mirror this for radial and island connections. E.g. recent cost increases for the Western Isles link have been attributed in part to discovery of more difficult ground conditions, which it is assumed will be passed through in locational charges. The costs of tunnelling on the mainland are not, however, passed through locationally, presumably in part because these costs are high and specific to ground conditions and so difficult to predict and generalise.

It's difficult to argue that generators shouldn't see a cost signal associated with the choices they make, but the islands at the moment appear captive to choices made by others at a late stage in development. This makes investment very difficult.

Whilst the level of charge is perhaps not something that the Connection and Use of System Code can address directly, relative cost reflectivity, predictability and stability do sit with the Connection and Use of System Code. Scottish Renewables therefore supports consideration of generic island expansion factors, perhaps even that remain fixed or index-linked for a particular asset rather than a price control period.

Sharing and Local / wider definitions

Scottish Renewables has participated in the development of a local sharing option for islands and is therefore naturally supportive of it. We will read others' feedback on the proposals with interest.

The local / wider debate around islands is largely one that is attached to sharing and how it applies to the islands. One concern is that islands might be dominated by one technology and that there is little sharing. Diversity attempts to address this but still has generic assumptions that do not fit the island context or indeed other circumstances that have a mix of low carbon generation with some sharing.

Another related concern is that generic assumptions on transmission investment are less likely to be applicable where there is just one single circuit connection to the mainland, and that in this instance a more specific approach is desirable. This could be addressed by a definitional change to local / wider or a different definition of sharing in the Original that doesn't use local / wider. Scottish Renewables supports the latter.

HVDC

The consultation has a comprehensive set of options for the treatment of HVDC and we don't have any major comments to add.

Process going forward

We are aware that for such a multi-faceted Modification, even simply putting together Alternatives will be a major task. It is through this process that the Working Group can influence the outcome, rather than the content, through influencing the choices (and the combination of choices) put forward to Ofgem. This is an important part of the process and it is essential that it is handled impartially and reasonably by the Working Group. Further to the point raised under 'Process and timescales', we feel that the workgroup should maintain focus on delivering outcomes that are fully developed and understood by industry and if this requires further or more analysis, any additional time required to do so should be minimised, and wherever possible, accommodated within the existing programme.

Scottish Renewables feels that each of sharing, islands and HVDC should be constructed as if they were separate Modifications so the content of one can't influence the attractiveness of another. Given the number of potential Alternatives for each one, we also feel that it is an unnecessary headache for the Working Group to have to build up one very large Modification from each of the three, and would ask the Code Administrator to consider whether it is possible to separate them for the purposes of going to Ofgem.

Summarising SR Response to specific Consultation Questions

Sharing

Q1 (geographic options considered) – we request further opportunity to shape alternatives – see above.

Q2 (sharing factor options) – we request further opportunity to shape alternatives – see above.

Q3 (peak security for intermittent generation) – no comment.

Q4 (sharing aspects) – we request further opportunity to shape alternatives – see above.

Q5 (differential impact of generators) – we request further opportunity to shape alternatives – see above.

HVDC

Q6-9 inclusive – we are content with WG's approach.

Island connections

Q10 (MITS/Local nodes) – please see "Sharing and Local/Wider" para above.

Q11 (Security Factor) – please see "Sharing and Local/Wider" para above.

Q12 (Expansion Factor) – please see "island expansion factors" para above.

Q13 (Anticipatory MITS) – no comment.

Q14 (island connection) – please see "Sharing and Local/Wider" and "island expansion factors" paras above.

Q15 (overall view) – please see "Sharing and Local/Wider" and "island expansion factors" paras above.

Implementation

Q16 (Which option) & Q17 (transitional approach) – please allow time to fully develop proposals. Each of sharing, HVDC and islands could be treated as if they were separate modifications. See "Process Going Forward" para above.

Governance

Q18 (Alternative Request) – no.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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*
Company Name:	*Sse PLC*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We welcome the opportunity to comment on the CMP213 proposal via this Workgroup consultation. We have answered the 19 questions posed by the Workgroup in detail below and therefore having nothing further to add here at this time.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	*. For reference, the Applicable CUSC Objectives for the Use of System Charging Methodology 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.* Firstly, we note the Proposer's view, outlined in the CMP213 Original proposal form submitted to the CUSC Panel on 29th June 2012 (and reproduced in Annex 2 of the consultation) about how this Original proposal does, in their view, better facilitate the Applicable CUSC Objectives for the Use of System Charging

	Methodology. Secondly, we note that CMP213 is still under development, both in terms of what will be the final composition of the Original and also what, if any, Alternative(s) might look like. Thirdly, we note that the Workgroup has itself still to consider if CMP213 Original (plus Alternative(s)) better facilitate the Applicable CUSC Objectives for the Use of System Charging Methodology. Therefore whilst, in principle, we agree with the views of the Proposer (back in June 2012, when raising CMP213 Original) that this proposal does better facilitate Applicable CUSC Objectives (a), (b) and (c) for the Use of System Charging Methodology this is just our initial view which may change, depending on what is determined (under the 'proposer ownership' principle) as being the Original after this consultation closes.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	We have reviewed the various potential options for implementing CMP213 (along with the suggestion of a possible transitional arrangement) and have provided detailed comments in Q16 and Q17 below.

Specific questions for CMP213 – see attachment – proforma not allowing multi-page answers.

Annex to SSE plc Response to CMP213 Stage 02 Consultation

Sharing [pg 27-103]

Q1 [pg 58] Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?

We note the deliberations of the Workgroup, as set out in Section 4 and have a number of observations.

We can understand the attempt to examine the variable elements affecting constraint costs and the discussion of this in paragraphs 4.33 to 4.100. However, we cannot reconcile the decision in paragraph 4.101 to "not look for a complex solution based on price" but that the Workgroup attempted instead to come up with a proxy for a price solution, which is as complex or even more so. We recognise that the Original provides a balance between complexity and practicability whilst being better in terms of cost reflectivity. However, we believe that the other options considered here are overly complex and do not provide a robust proxy for a solution based on price.

For example, we disagree with the proposition as illustrated in Figures 17, 18, 19, 20, 21, that there is one linear relationship between the load factor and incremental constraint costs of low carbon plant and a different linear relationship for non low carbon plant. We do not think that this has been clearly demonstrated and seems at odds with examination of actual bids and associated constraint costs.

This error (in terms of the five figures mentions above) is compounded by assuming that nuclear power plants have incremental constraint costs of a similar level to other low carbon plant when, in fact, such plants have, across the fleet, the highest Bid prices in the BM (at negative £10,000 for each plant).

This error (in terms of the five figures mentions above) is compounded by assuming that nuclear power plants have low incremental constraint costs when, in fact, such plants have, across the fleet, the highest Bid prices in the BM (at negative £10,000 for each plant).

One argument that has been put forward is that the published Offer prices of low carbon plant (nuclear and non nuclear) are closer together than those for non low carbon plant (such as CCGTs and coal).

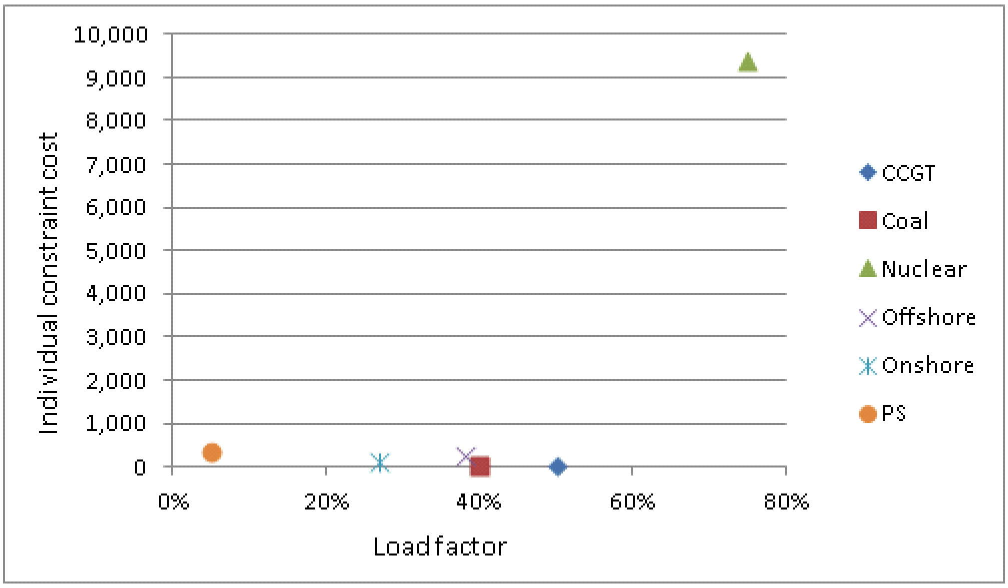
However, this is not born out by even a rudimentary examination of the facts. Taking nuclear generation Bid prices (at negative £10,000) as 100% and Bid prices of £0 as 0% then onshore wind generation, for example, has Bid prices in the region of negative £80-200 (or -0.8-2%) whilst non low carbon plant; such as coal and gas; have Bid prices in the region of positive £20-40 (or -0.2-0.4% in the reverse scale used in this simple example). Nuclear bid prices only vary to negative £9,900)

Thus it can be seen, via the published Bid prices, that renewable low carbon generation is far closer (in terms of incremental constraint costs) to non low carbon plant; being in a range of 1-2.4% (0.8 to 2% low carbon / -0.4 to -0.2% non low carbon) of the cost of nuclear low carbon (which varies by only 1% from the 100%).

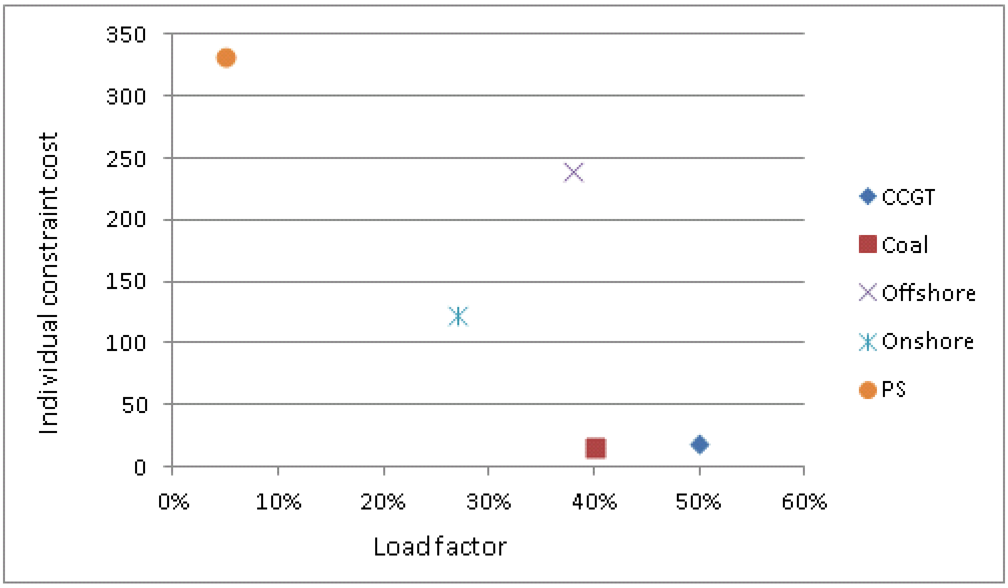
A further anomaly with this approach is that it appears that pump storage generation (where some Bid prices are higher than, for example, non nuclear low carbon generation) is included with non low carbon plant even though the range of offer prices is greater than the 1-2.4% range between non nuclear low carbon generation and non low carbon plant.

As a result we have serious reservations over some of the detail in the proposed 'diversity' approach set out in paragraphs 4.123-4.150 as it appears to distort the effect of the proposal by substantially altering the quantity of transmission capacity that is available to share between generators (especially in Scotland, and in particular the B6 Cheviot boundary).

We have reviewed bid prices for a range of plant, covering over 17 GW of plant, for one month from 24/11/12 to 24/12/12. (This period has been used as it is the most recent month available excluding the Christmas holiday period). In the following graph we show the calculated marginal constraint cost associated with these bids. This shows that there is not a strong relationship between plant load factor and bid cost according to the definition carbon and low carbon. The relationship is not clear as the bid cost of nuclear is so much lower than that for the other technology types.



Using a truncated scale for the constraint cost (y-axis) helps outline the relationship for the non-nuclear plant. Nuclear plant is excluded as its constraint cost is outwith the y-axis range. It is clear that the relationship between load factor and constraint cost does not split along carbon and low carbon lines.



In terms of the treatment of negative TNUoS zones, as set out in paragraphs 4.151-4.164, we concur that the Original proposal will be more cost reflective than the existing 'baseline' ICRP approach.

In this respect we agree, in particular, with the view that the existing 'baseline' ICRP approach "...is over rewarding these power stations in negative zones and more generally in the southern part of the GB transmission system". We note that as the amount of funds to be recovered from generation (across the whole of GB) remains the same that over rewarding of power stations in negative zones comes at a direct cost to those generators in positive zones. This is detrimental to competition in generation as it results in a subsidy being paid by generation in positive zones to those in negative zones. This does not better facilitate the applicable objectives – CMP213 by correcting this defect does, clearly, better facilitate the applicable objectives in terms of the charges applied to generators in negative zones.

We also would wish to raise the issue that CfD low carbon plant will not follow the same bid pricing as RO low carbon plant. In fact CFD plant may exhibit bid prices very similar to non low carbon plant. Hydro plant with storage, which does not have low energy spill cost, will also exhibit bid prices similar to non low carbon plant.

Q2 [pg 72] Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.

Taking into account the Workgroup deliberations, in paragraphs 4.165-4.247, we believe that all the practical options for calculating the sharing factor have been taken into consideration.

As has been indentified by the Proposer and the Workgroup in setting the ALF sharing factor a balance needs to be struck between three often contradictory elements:-

Simplicity / transparency;
Stability / predictability; and
Cost reflectivity.

We are persuaded that the benefits of the Original approach (five year ALF with the highest and lowest values discarded) as set out in paragraph 4.182 outweigh the dis-benefits set out in paragraph 4.183.

The TEC (MW) option is retention of the 'status quo' approach and does not therefore, in our view, better meet the applicable objectives on the ground of not being as cost reflective as either the original or some of the other options in table 15.

The main drawback of the NETS SQSS approach is that a wide range of generation technology categories is needed to allow the generic factors to align with actual load factors. This makes for complexity and uncertainty in terms of setting parameters administration as well as the potential of significant divergence between the generic load factor and the actual for most generators.

The generic approach also shares the drawbacks of complexity, uncertainty and the potential of significant divergence between the generic load factor and the actual for most generators.

We believe that this leaves the use of a forecast as the best practical option. In terms of a National Grid forecast we suspect this would, in practice, either be based on the ALF (or a variation of) or the NET SQSS approaches – so this would not be any better / worse than either of those approaches.

In respect of the User forecast, with a clear reconciliation approach to incentivise accuracy in that forecast we believe this may have merit as it addresses some of the perceived drawbacks with the ALF approach of the Original.

Taking all these factors into account whilst we support the Original proposal, we can see a distinct advantage (over and above the ALF) if the proposed Hybrid approach (of using either the ALF or a User Forecast) is adopted when determining the sharing factor. We therefore support this as our preferred option.

Q3 [pg 76] On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?

We note the deliberations of the Workgroup, set out in paragraphs 4.238-4.266. In our view the arguments set out in paragraphs 4.253 and 4.254 and the analyses presented in figures 33 and 34 point to intermittent generation not being exposed to a Peak Security element in their TNUoS tariff composition.

This is reinforced by the statement, in paragraph 4.26.2, that "...the deterministic standards against which transmission network capacity for demand security reasons is planned currently dictates that wind generation has no influence on the incremental need for transmission network capacity at times of peak electricity demand."

Q4 [pg 103] Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

Yes, we consider that all practical options have been considered, however we consider that some impractical options have also been considered. Thus if all options are to be retained for further consideration we think it appropriate that other options such as distinct plant by plant, stochastic based bid and output level pair based sharing are considered.

Q5 [pg 103] What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?

We believe that the general principle of load based sharing is incorporated into the methodology as there is a clear logic for this. We believe however that all attempts to make a clearer link to sharing potential for assets is likely to bear little in terms of improved cost-reflectivity whilst introducing a greater administration burden and the risk of discrimination based on non-representative models of the true impact of capacity sharing.

HVDC [pg 104-114]

Q6 [pg 111] Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.

Having reviewed the information set out in Section 5 it appears that all the relevant options and potential alternatives for how the expansion factor should be calculated have, so far, been considered.

However, we believe that the Workgroup has to fully recognise that the treatment of the only HVDC link under construction (which parallels the onshore AC network) within the charging methodology should reflect the fact that as the cost of both the onshore and offshore links are similar (or less) that the eventual charges should also be similar (or less) depending on the capacity of the onshore link.

In the absence of evidence from the TOs (or Ofgem) to the contrary we believe the capacity figure for both links are similar (at ~2.2GW) and therefore the effect on TNUoS tariffs should also be similar. It would, for example, be very odd for the two TOs concerned to have modelled a significantly greater onshore capacity for the onshore link (compared with offshore) as this would seem to undermine both their public statements (and those of Ofgem / DECC).

In coming to this view we have noted, in particular, the deliberations set out in paragraphs 5.46-5.54. Given that the published cost of the Western HVDC is in the order to £1,051M[1] and the capacity is in the order of 2.2GW[2] and that, according to the two respective TOs, the

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[1] Ofgem 27th July 2012 http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/Jul12_WHVDC_decision_FINAL.pdf

[2] Ofgem 21st May 2012 http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/CriticalInvestments/InvestmentIncentives/Documents1/TII_May12_WHVDC_consultation.pdf

cost is similar[3] to the parallel (onshore) AC 400kV circuits (and according to the regulatory bodies the cost, of going offshore, is less[4] than onshore) we would expect the cost, in terms of TNUoS tariffs, to also be similar (or indeed, based on the regulatory analysis, less) between the offshore cable and the onshore route.

In other word, for illustration purposes only, **if** the effect of building the onshore capacity was £1 (in terms of TNUoS tariff increases for those Users north of the B6 boundary) then the effect of providing that capacity via the offshore Western HVDC should be similar at £1; i.e. it might, say, be £0.95p or £1.05p depending on what the actual costs (as shown in the TOs CBA provided to Ofgem) was.

This is what any neutral observer would expect – the cost of the link is similar, the capacity is similar therefore, if the TNUoS charges are to be cost reflective then they too should be similar.

However, we note that it has been difficult to source what, approximately, is the capacity of the onshore parallel AC circuits that have been modelled / assessed by the two TOs involved in this project (and by Ofgem / DECC).

Clearly with the cost being similar (according to the TOs - or less according to Ofgem / DECC) at £1,050M if, therefore, the onshore capacity modelled was twice that of the Western HVDC at, say, circa 4.4GW then, in terms of the *illustrative* example used here, the effect on TNUoS tariffs (for those Users north of the B6 boundary), should be twice that of the equivalent parallel onshore network; i.e. in the order of £2 for going offshore compared with £1 for the equivalent onshore.

However, if for example the effect on TNUoS tariffs (for those Users north of the B6 boundary) of going offshore was 10 or 20 times greater then this clearly implies that the parallel onshore AC circuit capacity that was modelled by the two TOs (and reviewed by Ofgem / DECC) would be 10 times; i.e. 22.2GW; or 20 times (44.4GW) greater. This is

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[3] Joint SPTL/NGET Planning Statement Western Link (July 2012) paragraph 2.5.2. "Analysis of the existing onshore system showed that the volume of additional capacity required could only be provided through the construction of new transmissions circuits and upgrading of certain existing circuits. Due to the number and scale of these works it was concluded, in this particular case, <u>that the cost of onshore reinforcement would be similar to that of an offshore HVDC</u>."

[4] Joint DECC / Ofgem ENSG report 'Our Electricity Transmission Network: A Vision For 2020' (February 2012) [page 70] "A number of alternative onshore solutions were considered to increase the boundary capability of the B6, B7 and B7a boundaries. These included:

A number of projects have already been planned to ensure that the maximum capability (4.4GW) of the existing circuits can be realised. Further reinforcement would be required in the form of either two new 400kV transmission circuits: one from the West of Scotland to Lancashire and one from the East of Scotland to North East England or reconductoring existing 400KV double circuit between Harker and Strathaven and additional series compensation in these circuits to provide the necessary boundary capacity. These options were discounted for three main reasons:

(a) They did not represent the most economic solution. The total length of the new circuits would be in excess of 600km; <u>this resulted in a total project cost that was higher than the undersea HVDC option</u>.

(b) The construction of new onshore overhead line routes would have a greater disruption to land and higher visual impact.

(c) The timescales required to progress a project through the planning and consents process as prescribed in Appendix F would result in higher constraint costs.

For these reasons it was decided not to progress with onshore AC reinforcements."

because as the cost remains similar (or less) the only other variable, in terms of cost reflectivity, is the capacity to be built.

Only in this way could it be said that the TNUoS tariffs for Users north of B6 are cost reflective, with respect to the effect of building (and charging for) the Western HVDC link.

Our understanding is that the capacity of the onshore route is neither 10 nor 20 times that of the offshore cable and therefore cannot reconcile why the offshore cable should be so much higher (in terms of TNUoS charge) than the onshore route. That being the case, we believe that this aspect needs reconsidered by the Workgroup.

Q7 [pg 113] Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?

The treatment of the HVDC in load flow modelling should be dependent on how the expansion factor of HVDC is treated in order to accurately reflect the underlying reasoning behind the HVDC investment decision. If HVDC is treated with an expansion factor equivalent or lower than the alternative AC investment then it is reasonable to use a methodology that maximises flow on the HVDC. If HVDC is treated with a higher expansion factor then a methodology that minimises flow on the HVDC should be used as the logical expansion decision for the TO would not be to expand the HVDC system given its greater expense compared to the onshore options.

Q8 [pg 114] Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

We consider that, given that HVDC investments are not being sanctioned to deal with flow at peak demand, it is appropriate to give consideration to a method that reflects this in how circuit faults are treated. We suggest that a methodology that uses a cost multiplier of 1/1.8 for the HVDC circuit MW-kms be examined. This would reflect the fact there is no redundant HVDC capacity whilst recognising that the model incorporates a standard 1.8 security factor for the MW-km associated with the HVDC circuit. We consider that this gives a more appropriate cost reflectivity.

Q9 [pg 114] What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?

We have considered the options set out by the Workgroup in Section 5, and have the following comments.

a) i) Remove all converter costs from the calculation

We agree with those Workgroup members that believe that all the cost of the HVDC convertor station should be removed from the locational charge and, instead, be placed in the residual charge element of TNUoS tariffs.

In coming to this view we agree with the views of Workgroup members noted, for example, in paragraphs 5.21-5.24.

We note the counter arguments including "....that in order to use HVDC cable technology converter stations are necessary, that these converter stations add to the cost of this transmission technology and as such should be included in the locational signal..." (paragraph 5.26) and observe the same could be said about transformer and substations as without them the onshore AC circuits could not function.
Or to put it another way, paragraph 5.26 could be read as:

> "....that in order to use *onshore circuits transformers and sub stations* are necessary, that these *transformers and sub stations* add to the cost of this transmission technology and as such should be included in the locational signal..."

Clearly it has been a widely justified and supported principle (a principle that we whole heartily agree with) that certain fixed elements of the transmission system should be recovered of all users of system (via the residual charge). In our view HVDC convertor stations exhibit the characteristics of similar fixed elements of the transmission system and should, accordingly, be charged in the same way; i.e via the residual not the locational element of TNUoS.

a) ii) Remove some converter costs from the calculation

i) Remove a percentage of the HVDC converter station costs based on elements similar to AC substations

Whilst not detracting from our position set out under (a) (i) we nevertheless recognise the deliberations of the Workgroup (paragraphs 5.30-5.35) in considering if there are certain cost elements associated with HVDC convertor stations that could be considered 'fixed' and others 'locational'.

In light of the analysis of the typical breakdown of HVDC convertor station costs shown in Table 18 then if the arguments set out under (a) (i) do not carry the day then the approach proposed by the Workgroup in paragraph 5.35 would seem the next most suitable approach.

ii) Remove a percentage of the HVDC converter station costs based on controllability similar to QBs

Noting the Workgroup deliberations set out in paragraphs 5.36-5.44 and for the reasons we have just set out under (a) (ii) (i) above we agree with the suggested approach in paragraph 5.44.

Having taken into account the deliberations set out in paragraphs 5.30-5.44 we agree with those members of the Workgroup (paragraph 5.45) that both a 10% (for the QBs aspects) and a 50% (for the cost element aspects) reduction are fully justified.

a) iii) Treat HVDC cost as onshore AC transmission technology cost when calculating the expansion factor

For the reasons we have detailed in our response to Q6 above, we believe there is a very strong case to argue that the expansion factor associated with an HVDC which parallel onshore AC network should be similar to that onshore network where the costs are similar (or less) and the capacity is similar.

If this was not to be the case and the TNUoS charges, as a result, were different then this would clearly be (a) discriminatory and (ii) not cost reflective (and thus would not better facilitate the applicable objectives).

Equally, where the costs are similar (or less) but, for example, the parallel onshore AC network capacity is, say, double that of the HVDC link then a properly functioning cost reflective charge for the onshore option would be half that of the offshore option. (But not a tenth or twentieth)

Put another way, if the offshore charges are not, in this case, broadly double those for onshore then they too are (a) discriminatory and (b) not cost reflective (and thus do not better facilitate the applicable objectives).

i) Review the overhead factor (i.e. 1.8%) used when annuitising the capital cost in the calculation of the expansion constant

We welcome the thoughtful deliberations of the Workgroup, as set out in paragraphs 5.55-5.63, with respect to how the overhead factor for HVDC links might be annuitised.

These deliberations, and the analysis from Parsons Brinkerhoff, are a helpful contribution to the debate on this particular matter and we concur with the view set out in paragraph 5.63 namely that the greater benefits of simplicity and stability associated with using a single overhead factor (of 1.8%) for all transmission assets (be they onshore AC circuits or offshore HVDC circuits) outweigh the minor detriment to cost reflectivity associated with not having a more specific treatment (for HVDC).

ii) Calculate the 'desired flow', and hence impedance, by balancing flows across the single most constrained transmission boundary rather than all the transmission boundaries the circuit crosses

Having considered the deliberations of the Workgroup, as set out in paragraphs 5.64-5.68, and being mindful of the points we have made in response to Q6-Q8 above, we are of the view that the Original proposal (of reflecting the multiple boundaries crossed by the HVDC link) is the most appropriate.

In our view the use of the single transmission boundary approach (paragraphs 5.66-5.67) would:-

1) be inaccurate (as, clearly, multiple transmission boundaries are being crossed);
2) not reflect what happens in reality (in terms of SO system operation, as the crossing of all the transmission boundaries would be factored in by the SO in its determination, on the day, of the use of the HVDC link); and
3) not be cost reflective (as it would attribute the cost arbitrarily to a single transmission boundary).

Therefore the single transmission boundary approach should not be adopted.

Islands [pg 115-131]

Q10 [pg124] Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?

We note the deliberations of the Workgroup, as set out in Section 6, and concur that all the options and potential alternatives for island nodes classed as part of the MITS and those classed as local have been considered. Therefore we have not identified any other options which we would like the Workgroup to consider.

Q11 [pg 127] Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?

Being mindful (1) of the Workgroup deliberations, as set our in paragraphs 6.71-6.81, and (2) the Project Transmit Technical Working Group deliberations we concur that the most appropriate global locational security factor, in the case of islands not exhibiting redundancy on their linkage with the MITs is 1.0 (compared with the 1.8 applied elsewhere).

In respect of the matter of generator compensation (paragraph 6.75) and in particular "that generation Users would not be eligible for CUSC compensation for loss of the single transmission circuit element" we agree with this with respect to where the loss has been on the single circuit (to which 1.0 is applied).

However, for the avoidance of doubt, we would not support a removal of compensation to the generator if they are being charged (as part of their overall TNUoS charge) for more than a single transmission circuit (i.e. 1.8) and that element (rather than the single transmission circuit) failed. In such a situation the generator is entitled to compensation (as they are paying for the redundancy).

Q12 [pg 130] Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.

With respect to how HVDC links to the islands should be charged whilst noting the deliberations of the Workgroup in paragraphs 6.82-6.99, we believe that the points we have detailed in response to Q6-9 should equally apply where HVDC technology is used to connect islands to the MITS.

Briefly, we can see a case for all the HVDC Convertor Station costs being treated as fixed (rather than locational) and thus recovered via the residual.

Whilst some have suggested this principle might also be applicable to offshore transmission connections we note firstly that islands are intrinsically part of the 'onshore' transmission system as they have always been covered by the licensed areas of the three transmission companies (since privatisation) unlike offshore and secondly, they have actual customer demand (as opposed to 'station demand') associated with them.

Notwithstanding that, the approach whereby a proportion of the costs of the HVDC convertor station costs; i.e. the 10% for QBs (if applicable in terms of VSC v CSC convertor technology adopted on the link(s)) and 50% for similarities to AC; should be adopted if the full convertor station costs are not to be recovered via the residual.

Q13 [pg 131] Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.

The deliberations of the Workgroup in paragraphs 6.100-6.113, with respect to anticipatory investment and the associated 'achievement' of MITS status on an island prior to it actually occurring, highlight a number of benefits and consequences from adopting some form of anticipatory approach to charging for forthcoming transmission investment required as a result of (anticipated) generation investment.

These arguments, with respect to the benefits and drawbacks identified by the Workgroup, are finely balanced and, at this time, we are not persuaded that the benefits outweigh the drawbacks.

In addition we believe there may be some further, practical aspects to be considered, for example: how far in advance should the SO look (what is the timeframe for their 'window'); what if a generator 'gamed' the situation by creating a real project and a 'cardboard' project the connection date for which was constantly being pushed back (but still falling within the timeframe window that the SO would be taking into account)?

Therefore, taking it all into account, we currently believe that, whilst the Workgroup has considered the relevant options and alternatives, the application of an anticipatory approach, with respect to islands (or wider afield), should not be taken forward.

Q14 [pg 131] Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?

We note the various options identified by the Workgroup in, for example, the table after paragraph 6.12, table 19 and table 20 and the associated detail for these in Section 6. We believe that the Workgroup has adequately considered all the relevant options and potential alternatives for island connections at this time.

Q15 [pg 131] What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?

As we have set out in our response to Q11 and Q12 above, there are a number of items that we believe should be taken into account when determining the best way of including island connections comprising sub-sea cabling and / or HVDC technology into the TNUoS charging methodology.

Firstly, we consider that it is appropriate that the global security factor for islands not having redundancy on their linkage to the MITS is 1.0 and that in this case generation Users would not be eligible for CUSC compensation for loss of service caused by a failure of the single circuit.

Secondly, if a lowered global security factor is not applied to islands not having redundancy on their linkage to the MITS, generation Users must be entitled to CUSC compensation for loss of service equivalent to mainland MITS generation Users.

Thirdly, we consider that HVDC Convertor station costs should be treated as fixed as opposed to locational costs, equivalent to how transformers and substations are treated in the baseline ICRP, and included in the residual.

Finally, we consider that an appropriate proportion of the HVDC convertor costs are excluded from the locational cost if the full convertor station costs are not to be recovered from the residual.

Q16 [pg 137] The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.

We have considered the four implementation options set out in Section 8 of the report.

It is important in considering implementation options that implementation of the charging methodology modifications should not be further delayed. Given that industry has been working on this since September 2010 the Workgroup timetable should not be allowed to slip further in order to analyse more options. Any additional analysis should be undertaken in parallel but within the current timescale.

In our view Option 1 (mid year 2013-14) is the preferred option with, as a fallback, Option 2 (1st April 2014).

In coming to this view we are mindful of the Authority Direction issued to National Grid and in particular the comments in the covering letter[5], of 25th May 2012, that:-

"Industry will decide the manner and timing of the industry process, but we continue to urge industry to expedite this process and submit a final CUSC modification proposal report, with all the requisite justification and evidence, in a timely manner to ensure benefits are realised as quickly as possible."

We note that industry has been aware of the possibility of a substantial change to the basis on which TNUoS tariffs are calculated since at least September 2010.

For example, the initial Project Transmit SCR Call for Evidence was published[6] on 22nd September 2010 and concluded, with a direction to National Grid, on 25th May 2012.

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5 http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20SCR%20cover%20letter%2025%20May.pdf

We further note that Ofgem has been seeking the expeditious implementation of a long term solution to TNUoS charging associated with its Project Transmit since its inception with, for example, a number of Ofgem statements referring to a possible implementation date of 1st April 2012:-

i) Ofgem 'Project Transmit: approach to electricity transmission charging work' letter 27th May 2011[7]

"If appropriate, we aim to implement any change to TNUoS in time for the next charging year, i.e. from April 2012."

ii) Ofgem Project Transmit Stakeholder event 11th August 2011 'Opening Presentation' (slide 4)[8]

"*New Charges Target Date Apr 12*"

iii) Ofgem Project Transmit Stakeholder event 11th August 2011 'Closing Presentation' (slide 2)[9]

'Implementation'

•*Initiate CUSC process and NGET 2012/13 tariff development –December 2011*

•*Aiming for change, if appropriate, by April 2012–feasibility to be discussed at WG and through consultation process*

•*Ultimately, industry will decide the manner and timing of implementation*

iv) Ofgem 'Project Transmit: electricity transmission charging Significant Code Review update' 9th September 2011[10]

"...*Implementation of any change, if appropriate, would therefore be after April 2012, the potential implementation date we identified previously*."

Thus, in our view, Users (and especially those with generation assets, who will be directly affected by the CMP213 associated changes to TNUoS) have had sufficient time to factor the possibility of a substantial change to the methodology for calculating TNUoS tariffs (for generation) into their normal day-to-day risks.

Given (i) that the Authority seeks the expeditious implementation of a long term solution to TNUoS charging associated with its Project Transmit and (ii) that Users will have had (with a mid 2013-14, Option 1, implementation) circa three years notice of the broad intent along with circa 18 months notice of the broad tariffs that Option 1 is the most appropriate implementation approach.

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[6] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Networks/Trans/PT[7] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf

[7] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/110527_TransmiT_charging_letter.pdf

[8] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20opening%20presentation.pdf

[9] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Ofgem%20closing%20presentation.pdf

[10] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=151&refer=Networks/Trans/PT

In regard to the other implementation options, as noted above, we consider that Option 2 has merit (as a fallback to Option 1) in that it exhibits the broad attributes of Option 1 (expeditious implementation) whilst allowing for implementation on the 'traditional' 1st April charging change date.

<u>We believe that any claimed impact on electricity supply tariffs is overplayed. Given that demand TNUoS charging is unchanged, and is now excluded from the SCR process, the only direct link between CMP213 and supply tariffs would be through the impact of CMP213 on wholesale prices. There has been no clear evidence produced to suggest that wholesale prices would increase under implementation of any of the options. In addition, wholesale price risk is a normal risk catered for by market participants.</u>

Q17 [pg 138] The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.

We note the deliberations of the Workgroup, as set out in paragraphs 8.26-8.31, with respect to transitional arrangements. Given that parties have had significant advance warning of the risk of this change (as detailed above in our response Q16) we do not believe that a transitional approach is required with respect to the implementation of CMP213.

In particular we find the suggestion that such a transitional approach, with respect to demand users, is (1) required and (2) needs to be over many years to be unsubstantiated, particularly as demand TNUoS charging is unchanged and is excluded from the SCR process.

If this were to be accepted then, on the grounds on non-discrimination, it would have to be applied to <u>all</u> changes to the TNUoS charging methodology in the future as well as any changes to the actual tariffs. (Some generation plant is likely to see a change to their tariff in excess of 20% across the period from 2012/13 to 2013/14)

It would also seem to be directly at odds with the Authority decision with respect to the 'mid-year' TNUoS tariff changes introduced on 1st December 2010 where timely implementation (outwith the 'traditional' 1st April date) was applied in order to better meet the applicable objectives, rather than delaying till the following spring.

With respect to generation TNUoS charges, Suppliers have been unable to show (a) that they have a significant proportion of their demand customers under long term contract (b) that those contracts are 'fixed' when it comes to the TNUoS methodology charges (e.g. they are not a 'pass through' element which alters as per the published TNUoS tariffs) and (c) that those contracts are directly linked to a specific generator, as opposed to being costed on the basis of the wholesale market price.

In respect of (c) we note that the proposed changes to the TNUoS charging methodology proposed by CMP213 will have no impact on the overall amount of money to be recovered from GB generators. Therefore whilst generators in certain parts of GB may, in the eyes of some, be considered to have 'lost' (if CMP213 is implemented) and others to have 'won' the overall effect on the GB wholesale price should be limited and may actually be positive.

Therefore there should be minimal negative, if any, impact on Suppliers and consumers, as Suppliers have costed their contracts with those customers based on the wholesale price.

Given that CMP213 original is, in our view, more cost reflective than the baseline (i.e. ICRP) we believe that any cost increase (in terms of impact on Suppliers) is firstly not proven, secondly even if it did exist is minimal (in the extreme) and, as a result, is far outweighed by the significant benefit associated with improved cost reflectivity and thus better facilitating competition in generation that arise from implementing CMP213.

Q18 Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?

We do not wish to raise a Workgroup Consultation Alternative Request.

Q19 Do you have any other comments?

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	Nick Oppenheim and Nick Kay on behalf of Uisenis Power Limited
Company Name:	Uisenis Power Limited
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are satisfied that the consultation is a comprehensive and well thought through process. At this stage however it is difficult to understand how the various options and alternatives will feed through to the resulting transmission charges. It would be helpful to see preliminary tariff assessments for the key options and alternatives taken forward as soon as this is available.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	In terms of facilitating effective competition the Original proposal is an improvement in recognising the different costs imposed on the transmission system by different types of generator and charging them accordingly, allowing fairer competition between generators of different types. However this should be applied to all parts of the transmission system, whether classed as wider or local, and should therefore apply to islands. Also, where demonstrated to occur, sharing should be applied to generators of the same type. There are aspects of the Original that would not help facilitate effective competition. For example the use of new technology, such as HVDC, can offer significant technical and environmental benefits over traditional AC solutions, and yet the methodology proposed in the Original could see generator TNUoS levels higher than had inferior, and more costly, AC solutions been implemented. The use of HVDC technology in the transmission network should not be hindered by a charging methodology that simply passes 100% of the costs to the connecting generators. The island links will be implemented as extensions to the onshore transmission network and as such any methodology adopted must seek to make island charges consistent with those

	of the mainland to ensure that island generators can compete on an equal footing with mainland renewable generation. This is essential to facilitate effective competition between generators otherwise there is a risk that a number of GWs of high quality renewable generation may not be connected. Our thoughts are explained further in the responses below.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	It would seem appropriate to work towards implementation of the modification for 1 April 2014. It is also noted that there could be a case for Ofgem to authorise National Grid to undertake preparatory work on generation TNUoS tariffs prior to Ofgem's final decision, this would be helpful.

Specific questions for CMP213

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	1.1 Whereas the Original proposal, accounting for sharing based on load factor, addressed sharing in areas dominated by certain generation types, the alternatives based on diversity between low carbon and carbon generation do not. Our thoughts are outlined further in Q2 below.

Q	Question	Response
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	2.1 We understand that the Original proposal, accounting for sharing based on load factor, would see benefit for generation users in Northern Scotland through reduced TNUoS (Northern Scotland would reduce by around £10/kW from the current £22/kW). 2.2 It is noted that the introduction of 'Diversity' would serve to dilute the reduction for Scotland arising from the Original, by introducing the concept that sharing only occurs between carbon and non-carbon generation. It would be very helpful to understand how this would impact wider TNUoS in northern Scotland, although it would appear that the northern Scottish zones, where levels of carbon generation are low, would be most impacted by this. 2.3 We also note that the work undertaken by Heriot-Watt University on island sharing proves that sharing does in fact occur between low carbon generators. We are therefore of the view that the alternatives put forward on Diversity would not accurately reflect the level of sharing on the network, and sharing between low carbon generators would need to be incorporated into any Diversity methodology. We would also be concerned at the level of complexity, and therefore transparency, that the proposed alternative on Diversity would bring to the application of the TNUoS tariff. 2.4 The Heriot-Watt work demonstrates that sharing does occur between low carbon technologies on the islands. However it assumes that all island wind turbines will operate as a single generator, peaking at the same time. This would not happen in reality, where different wind farms, as close as a few km apart, would not necessarily peak at the same time. Indeed individual turbines within the same wind farm can perform quite differently, especially in complex terrains and in high wind conditions, as can be experienced on the Scottish islands. We therefore believe that the Heriot-Watt findings are conservative when it comes to the level of sharing between renewable generators.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	3.1 We believe this has been covered by the Workgroup.

Q	Question	Response
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	4.1 The work on sharing between low carbon generators, as demonstrated by Heriot-Watt, needs to be developed further and possibly incorporated into the alternatives developed for Diversity, as outlined in Q2 above.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	5.1 Where sharing occurs, whether between generators of different technology or between generators of the same technology, then it should be reflected in the TNUoS tariff. This applies equally to wider and local elements, and therefore islands. However, the charging methodology does have to balance complexity with a level of transparency to make any methodology workable, and it could be that cost reflectivity is best served by using a simple, but generator specific, load factor – as in annual load factor (ALF).

Q	Question	Response
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	6.1 We recognise that a generic HVDC expansion factor determined from an average of HVDC project costs would be difficult to determine due to the limited number, and bespoke nature, of each HVDC circuit/connection. 6.2 We note that generic factors used for the AC transmission network allow for averaging of costs and would be likely to result in lower TNUoS levels for generators had AC solutions been adopted for the island connections. 6.3 We understand that the 2010 assessment for the Western Isles Link compared HVAC and HVDC solutions. The AC solutions were significantly more expensive, and yet the use of generic expansion factors and exclusion of the costs of fixed assets would result in a lower TNUoS for the generator. In addition generic expansion factors based on average costs avoid potential increases in locational TNUoS if specific costs should rise. 6.4 We would accept that a specific island expansion factor, to be determined on an island by island basis, could be appropriate for the new HVDC links. However this expansion factor should exclude the appropriate fixed cost elements. Removing cost elements will also lessen the potential for sudden price increases and help competition with mainland generators benefitting from generically determined TNUoS. 6.5 The use of AC generic expansion factors is also a feasible alternative where HVDC circuits are shown to have equivalent, or indeed lower, overall capital costs compared to equivalent AC solutions. 6.6 Generic factors would also help avoid sudden TNUoS price increases. For example, on the Western Isles the capital costs of the link have recently increased, and under the Original these cost increases would be passed through in full to the generators already committed to the connection and with user commitment in place. A significant factor in the cost increase has been the ground conditions of the underground cable section. Had an AC solution been implemented the generator would have been protected from these increases through the generic AC cable expansion factor.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	7.1 We believe all options have been satisfactorily covered by the Workgroup.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	8.1 Picked up in responses to other HVDC questions.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	9.1 In line with island links we believe that it would be wrong to simply place all costs for the parallel circuits in the expansion factor. It is important to recognise, that whilst HVDC technology is relatively new, it has significant benefits compared to traditional AC technology. 9.2 We believe that the basic functionality of HVDC converters is the same as AC substations in that they transform electrical power into a form suitable for long distance transmission, and at the receiving end step is back in to a form suitable for distribution. As evidenced in the consultation report, costs could be less than AC solutions, and environmental impact will be significantly less. We believe that for the parallel links it would be reasonable, as a minimum, to exclude from the expansion factor the costs of the equivalent AC components, including substation and compensation equipment.

Q	Question	Response
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	10.1 We note that under the current definitions the Western Isles will become part of the wider network following the installation of the Western Isles Link (two transmission circuits supplying a GSP). However, we would see that island nodes could be classed as local, although we would see that this would only be on the basis that: • The Original proposal is then be adopted for wider sharing based on load factor • Local sharing is applied to each island circuit effectively enhancing the circuit rating for charging purposes. Local sharing should be forward looking and codified and could be determined and from the mix of generators with user commitment in place for each island link. The Heriot-Watt methodology, updated to include sharing between renewable generators (as detailed in paragraph 2.4), could be used as the basis to determine the level of sharing.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	11.1 We note that a security factor of 1 is proposed for island connections, and would agree that this would be appropriate for single circuit island links whether classed as wider or local.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	12.1 We note the options to deal with the costs of the converter stations, from all costs included in the expansion factor, to all costs excluded from the expansion factor, or a share between the two. As such we believe that the Workgroup has sufficiently considered the options. 12.2 However, under current methodology AC substations are excluded from the expansion factor, as are other fixed AC assets such as static compensation equipment and quadrature boosters. We believe that the basic functionality of HVDC converters is the same as AC substations in that they transform electrical power into a form suitable for long distance transmission, and at the receiving end step is back in to a form suitable for distribution. 12.3 We concur with the logic to exclude the AC elements of HVDC converters from the expansion factor. However, the DC element of the converters is able to offer significant benefits over passive AC systems, in that it is controllable, and can provide wider benefits to the networks to which converters are embedded. This is particularly relevant for HVDC converters based on Voltage Source (VSC) technology, our thoughts are outlined in more detail in the Island section. 12.4 To treat HVDC converters differently to AC substations because they are more expensive is too simplistic, and consideration should be given to the overall costs of all sections of the HVDC link (converters, subsea cable sections and underground cable sections) compared to an equivalent AC solution, as detailed in our response to Q14. AC cables for example are more expensive than HVDC, yet generic AC cable expansion factors are used to determine AC TNUoS levels that could be lower than HVDC. 12.5 We believe that it would be appropriate to remove all of the HVDC converter costs from the locational element, recognising the benefits of the new technology and also leading to TNUoS levels comparable with equivalent AC solutions with similar capital costs.

Q	Question	Response
12	Cont/	12.6 We note there are contrasting views in the report over the HVDC precedents established by offshore wind connections. We would argue strongly that HVDC, especially for island connections, should be dealt with independently from offshore connections. Whilst there are some similarities, there are also important commercial and technical differences between the two types of generation: • A specific regulatory framework has been established for offshore wind to facilitate the development of offshore wind technology, including higher levels of policy support and the OFTO arrangements in respect of the connection arrangements. • Island generators see the same levels of policy support to mainland onshore generators, and the island links will be implemented as extensions to the onshore TO's Transmission Licence area, they are not part of an OFTO's Transmission Licence. • Offshore connections tend to be specific links to individual generator stations whereas the island links will connect multiple generator stations covering different technologies. The island links will also serve to benefit the islands themselves improving the quality and security of supplies in these remote areas, providing capacity to facilitate island demand growth, and relieving reliance on local carbon standby generation. The new link to the Western Isles will relieve the heavily congested circuit to Skye, with demand being transferred to the new link.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	13.1 We consider all options have been covered.

Q	Question	Response
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	14.1 In terms of what has been considered, we believe that it would be wrong to simply place all costs for the island links in the expansion factor. It is important to recognise, that whilst HVDC technology is new, it can perform better than traditional AC technology, it has been demonstrated to be cheaper, and will have less of an environmental impact. 14.2 VSC based converter technology proposed for the island links is very controllable and in the correct circumstances installation of HVDC VSCs links can be beneficial to overall transmission system performance. 14.3 We understand that the Western Isles Link converter at Beauly will be used to support system voltage and will improve system stability in an important part of the network, the island converter will improve quality and security of supplies for the island. The black start capability of VSC converters will benefit the island following outages, restoring supplies without the need to start up standby diesel generation. 14.4 We understand, from the TNEI and PB Power reports published in 2010, that the costs of the preferred 450MW HVDC solution for the Western isles Link were lower than the AC solutions of the same rating considered at the time. 14.5 There are also important environmental benefits from the use of HVDC technology, cables are smaller and fewer are required, they are therefore easier to install underground, or sub-sea. Cables can be used over longer distances than AC, avoiding the need to use overhead lines. VSC converter stations have relatively small footprints, and the majority of equipment can be housed indoors. 14.6 For the proposed Western Isles Link, we understand that SHETL assessed all options taking into account technical, economic and environmental factors and concluded that a VSC based HVDC solution offers the optimum solution.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	15.1 Any solution for the island links should not be compromised by comparisons with elements of the offshore charging methodology, which has a completely separate and independent regulatory framework. 15.2 The island links will be implemented as extensions to the onshore transmission network and as such any methodology adopted must seek to make island charges consistent with those of the mainland to ensure that island generators can compete on an equal footing with mainland renewable generation. 15.3 HVDC is a relatively new technology which can offer significant technical and environmental benefits over traditional AC solutions, and yet the methodology proposed in the Original could see generator TNUoS levels higher than had inferior, and more costly, AC solutions been implemented. The use of HVDC technology in the transmission network should not be hindered by a charging methodology that simply passes 100% of the costs to the connecting generators. 15.4 Where sharing occurs, whether between generators of different technology or between generators of the same technology, then it should be reflected in the TNUoS tariff. This applies equally to wider and local elements, and therefore islands. Local sharing should be forward looking and codified, and applied to each island circuit effectively enhancing the circuit rating for charging purposes. Appropriate sharing could be determined from the mix of generators with user commitment in place for each island link.

Q	Question	Response
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	16.1 It would seem appropriate to work towards implementation of the modification for 1 April 2014. 16.2 It is also noted that there could be a case for Ofgem to authorise National Grid to undertake preparatory work on the generation TNUoS tariffs prior to Ofgem's final decision, this would be helpful.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	17.1 It would seem appropriate to work towards implementation of the modification for 1 April 2014, as above.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No.
Do you have any other comments?		No.

CUSC Workgroup Consultation Response Proforma

CMP213 - Project TransmiT TNUoS Developments

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 **15 January 2013** 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

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:	John Cunningham, Strategy Manager, Comhairle nan Eilean Siar, 07789 878840, jcunningham@cne-siar.gov.uk
Company Name:	**Comhairle nan Eilean Siar, Local Authority for the Western Isles of Scotland**
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	The consultation is detailed and well developed but indicative tariffs for each of the options being considered would be useful.
Do you believe that the proposed original better facilitate the Applicable CUSC Objectives? Please include your reasoning.	A purely cost reflective regime disadvantages the Scottish islands. The islands should not be penalised for pioneering HVDC technology through a direct 100% reflection of the cost of HVDC. Elements of the Radial Links should be removed from the charging calculation to better reflect parity with the mainland AC based charging methodology. These differences in approach do not facilitate effective competition.
Do you support the proposed implementation approach? If not, please state why and provide an alternative suggestion where possible.	No Comment

Specific questions for CMP213

Q	Question	Response

Q	Question	Response
1	Do you believe that the Workgroup has fully considered the range of options for addressing how charging structures should be applied geographically to areas dominated by one type of generation, including on local circuits? If not, what other options would you like the Workgroup to consider and why?	Further consideration should be given to the extent of sharing on island circuits. The sharing argument seems to focus on 'dominant generation types' and insufficient consideration is given to diversity between low carbon technologies.
2	Do you believe that the Workgroup has sufficiently reviewed all the necessary options on how a sharing factor (i.e. ALF) could be calculated. Are there any areas that you think may need further development? If so, please specify along with an associated justification.	More use should be made of the Heriot Watt analysis in Orkney which is applicable to all islands.
3	On the subject of whether intermittent generation should be exposed to a Peak Security element of the tariff, do you have any views in addition to those discussed by the Workgroup?	No comment.
4	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *sharing* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	Again, more use should be made of the Heriot Watt analysis on sharing. An island sharing factor should be developed which is anticipatory in order to better inform long run investment decisions by generators.
5	What are your overall views on how best to reflect the differential impact of generators with distinct characteristics on incremental network costs into the TNUoS charging methodology?	TNUoS should be based on usage and not on installed capacity. Installed capacity as a basis for TNUoS calculation is outdated. Recognition should be made of the inevitable downtime of intermittent generators.
6	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the expansion factor (i.e. unit cost) for an HVDC circuit paralleling the AC network should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	A specific Island Expansion Factor for HVDC should be developed which excludes non-relevant cost items from the calculation, eg certain non-Transmission Converter Station costs. The mainland benefits from generic Expansion Factors which insulate TNUoS from fluctuations in the cost of specific projects. This is not the case for the islands, particularly in regard to recent cost increases in the Western Isles Link which could be passed on directly to TNUoS.

Q	Question	Response
7	Do you believe that the Workgroup has satisfactorily considered all the options and potential alternatives for how an HVDC circuit paralleling the AC network should be modelled in the DC load flow element of the TNUoS charging calculation? If not, what other options would you like the Workgroup to consider and why?	No comment.
8	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the *HVDC circuit* aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	No comment.
9	What are your overall views on how best to incorporate HVDC circuits that parallel the AC network into the TNUoS charging methodology?	Non-transmission elements of Converter Station costs should be excluded from the TNUoS calculation
10	Do you believe that the Workgroup has considered all the options and potential alternatives for island nodes classed as part of the Main Interconnected Transmission System (MITS) and those classed as local? If not, what other options would you like the Workgroup to consider and why?	If any of the islands are to be treated as MITS, an effective sharing factor, across all technologies, must be introduced for consistency. Again, more use should be made of Heriot Watt's analysis and this sharing factor should be anticipatory in order to support advance investment.
11	Do you believe that the Workgroup has considered all relevant options and potential alternatives for how the global locational security factor could be applied to island connections with little or no redundancy? If not, what other options would you like the Workgroup to consider and why?	Since there is no redundancy in the island links, a Security Factor greater than 1.0 can not be charged. The Comhairle would like to see a Security Factor of 1.0 whether links are classified as Local or MITS.

Q	Question	Response
12	Do you believe that the Workgroup has sufficiently considered the options and potential alternatives for how the expansion factor (i.e. unit cost) for sub-sea cables and/or radial HVDC circuits forming part of an island connection should be calculated for inclusion in the TNUoS charging calculation? If not, please provide suggestions with an associated justification.	In all other aspects, the Western Isles are an integral part of Scotland and the United Kingdom. However, when it comes to electricity networks, the Western Isles are treated as offshore generators with no local demand and no network sharing. Charging the absolute cost of HVDC links against TNUoS results in a forecast Western Isles TNUoS SEVEN TIMES the North of Scotland mainland, only 28 miles away across the water. This is a clear case of the islands being disadvantaged by national policy and represents a breach of European Directive 2009/28/EC. Island TNUoS should be pegged to the nearest mainland TNUoS, maybe no more than two times the corresponding mainland charge and the difference should be socialised. This is a small cost for OFGEM to pay for GW's of renewable energy, produced at a fraction of the subsidy cost of Offshore Wind. In the wider sense, island Renewable Energy provides unprecedented regenerative opportunities to the most fragile economies in the UK at little cost to the Government and removes the need for continued Government intervention by subsidy should the Renewable Energy industry not develop.
13	Do you consider that the Workgroup has adequately considered all relevant options and alternatives for an anticipatory application of the MITS definition to island nodes? If not, please provide suggestions with an associated justification.	MITS with a Security Factor of 1.0 should be applied anticipatorily to all island links. This will give needed certainty to prospective developers.
14	Do you consider that the Workgroup has adequately set out and considered all relevant options and potential alternatives on the "island connection" aspect of this modification proposal? If not, what other options would you like the Workgroup to consider and why?	The UK's electricity transmission system requires to be reversed in order to collect GW of electricity from Europe's area of best Renewable Energy resource around the Scottish Islands. The current TNUoS methodology simply consolidates an outmoded and unfit Fossil Fuel based network through a series of locational signals which effectively disadvantage the Scottish Islands. The benefits of HVDC technology to the wider network should also be taken into consideration in calculating island TNUoS.

Q	Question	Response
15	What are your overall views on how best to include island connections comprising sub-sea cable and/or HVDC technology, such as those proposed in Scotland, into the TNUoS charging methodology?	a) the islands should be treated for what they are – an integral part of the UK network which can provide GW's of power for consumption in UK (and European) urban centres at a fraction of the cost to consumer of Offshore Wind; b) HVDC technology is new and the islands should not be penalised for early adoption through absolute reflection of the full cost of this technology. Different pricing methodologies are being used for the mainland (generic AC Expansion Factors) and the islands (absolute 100% cost reflection of HVDC by project). This is clear disadvantage in European terms; c) sharing between low carbon technologies should be developed without delay and applied anticipatorily in order to support onshore wind but also marine technologies where Scotland has the potential to be a global leader; d) locational signals which disadvantage the islands (SEVEN TIMES higher than the nearest mainland) should be tempered by imposing a cap on island TNUoS relative to nearest mainland TNUoS with the difference socialised as an incentive to island generation.
16	The CMP213 Workgroup would welcome your views on which, if any, of the four implementation options set out in Section 8 should be adopted.	Production of indicative tariffs for the various options would be helpful.
17	The CMP213 Workgroup would welcome your views on (a) whether or not there should be a transitional approach to the implementation of CMP213 and, if so, how many working days notice period should be allowed as well as (b) what those transitional arrangements should be.	No comment.
18	Do you wish to raise a Workgroup Consultation Alternative Request for the Workgroup to consider?	No comment.

Do you have any other comments?	Indicative tariffs by option are essential for any effective assessment of Working Group outputs and should be developed as soon as possible. A generic Island Expansion Factors should be introduced to insulate committed island developers from ridiculous cost increases (the cost of the Western Isles Link rose by 70% in three months during 2012).