nationalgrid

Stage 04: Code Administrator Consultation

Connection and Use of System Code (CUSC)

CMP268

‘Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits

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

CMP268 aims to change the charging methodology to more appropriately recognise that the different types of “Conventional” generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of “Conventional” generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator’s ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements.

This document contains the discussion of the Workgroup formed in August 2016, responses to their consultation and the Workgroup’s final conclusions.

Published on: **20 October 2016**
Length of Consultation: **10 Working days**
Responses by: **3 November 2016**

High Impact: Generation TNUoS payers.

The Workgroup concludes:
Five out of the six Workgroup concluded that the Original proposal did not better facilitate the CUSC Objectives and therefore that the baseline was the best option. One Workgroup member concluded that the Original proposal better facilitated the applicable CUSC objectives and should be implemented.

Contents

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About this document

The purpose of this document is to consult on CMP268 with CUSC Parties and other interested industry members. Representations received in response to this consultation document will be included in the Code Administrator's draft CUSC Modification Report that will be furnished to the CUSC Panel for their recommendation to the Authority. Parties are requested to respond by **5pm** on **3rd November 2016** to cusc.team@nationalgrid.com using the Code Administrator Consultation Response Proforma which can be found via the following link:
http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/

Document Control

Version	Date	Author	Change Reference
0.1	14/10/2016	Workgroup	Workgroup report to CUSC Panel
0.2	20/10/2016	Code Administrator	Code Administrator Consultation to Industry

1 Summary

1.1 CMP268 was proposed by SSE and was submitted to the CUSC Modifications Panel for their consideration on 27 July 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the CUSC Applicable Objectives. The Authority determined that the proposal should be considered on an urgent timescale. The letter from the Authority setting out the reasons for urgency is set out in Appendix 6. The timetable for urgent consideration is set out in the Terms of Reference in Appendix 2.

1.2 CMP268 aims to change the charging methodology to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator's ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements. This does not change the way the Year-Round tariff is calculated and it does not change existing generator classifications, but it does change the formula by which the Year-Round tariff is applied to different types of Conventional generator.

1.4 At the CUSC Modifications Panel meeting on 18th October 2016, the Workgroup Report was presented to the CUSC Panel and the Panel agreed that the Workgroup had met their terms of Reference and accepted the Workgroup Report. The panel agreed for CMP268 to progress to Code Administrator Consultation for a period of 10 Working days.

1.6 This Code Administrator Consultation has been prepared in accordance with the Terms of the CUSC. An electronic copy can be found on the National Grid Website http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/, along with the CUSC Modification Proposal form.

Workgroup Conclusions

1.3 At the final Workgroup meeting, Workgroup members voted on the Original proposal. One of the Workgroup members voted that the Original Proposal better facilitated the applicable CUSC objectives as it is more cost reflective in the Capacity Market and wholesale power market and takes better account of developments in the Transmission businesses. The remaining 5 Workgroup members voted that the Baseline is better against the applicable CUSC Objectives because it is not clear that applying ALF to the non-shared element is more cost reflective and that current cost signals are correct when applying diversity in a zone.

2 Background on the Proposer's view of the defect

2.1 The modification proposal set out the proposer's views on the nature of the defect and the potential solution. Note that this section is representative of the Proposers view and is not a view that is wholly supported by Workgroup members. Counter arguments to these views can be found in Section 3 of this Workgroup report in the Workgroup discussions.

Context of the CMP268 Original proposal

2.2 Prior to 1 April 2016, the TNUoS charging methodology applied the same TNUoS tariff formula to all classes of generator based on 100% of their Transmission Entry Capacity (TEC). The Authority considered that there may be an opportunity to improve the cost reflectivity of the charging methodology, therefore on 25 May 2012, the Authority directed NGET[1] to raise a Modification proposal to the CUSC to ensure that it better reflects the costs imposed by different types of generators on the electricity transmission network (a.k.a. network **sharing**). This direction also related to the treatment of **High Voltage Direct Current** (HVDC) circuits and **island connections**).

2.3 It followed that the CMP213 CUSC Modification Proposal was submitted to the CUSC Modifications Panel (the Panel) for their consideration on 29 June 2012 which proposed changes including the creation of two different backgrounds within the ICRP Transport model (Peak Security and Year-Round), and an associated new TNUoS tariff formula consisting of a Peak Security tariff element (paid by all generators except those classed as intermittent) and a Year-Round tariff element paid by all generators. CMP213 Original also proposed that for each generator, the Year-Round tariff element should be adjusted by being multiplied by each generator's Annual Load Factor (ALF) to better reflect the network investment cost which they cause according to the Economy Criteria of the NETS SQSS and also better reflect a full Cost Benefit Analysis (CBA). During the CMP213 Workgroup process, many different alternatives to this approach were considered including the alternative which became defined by Workgroup Alternative Modification Proposal 2 (WACM2).

2.4 WACM2 proposed that the charging methodology could be even more cost reflective if it took account of the degree of diversity behind a network boundary. This was based on the reasoning that when the network flows on a particular circuit are dominated by generators who are very expensive to constrain off (due to high negative bid prices), then those generators will tend to cause a level of required network investment of those affected circuit at a level closer to 100% of their TEC instead of proportional to their ALF. The Proposer noted that the economic rationale was that even if those expensive bid price stations were involved in a relatively small volume of network constraints, then the high cost of constraining them off would mean that it may tend to be more economically viable to invest in sufficient transmission network capacity such that those stations with expensive bid prices would need to be constrained off rarely, or not at all in order to manage network constraints.

2.5 On 25 July 2014, the Authority considered the selection of alternative proposals which were presented to it and decided to approve WACM2 with an implementation date of

[1] http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/Final%20direction%2025%20May%202012.pdf

April 2016. This decision was challenged through a Judicial Review, then on 23 July 2015, the Judgement was handed down that The Authority's decision was correct as per the following extract from the conclusion of the judgement:

2.5.1 "[64.] The decision of the Authority to approve the modification known as WACM 2 to the charging methodology relating to the recovery of costs incurred in connection with investment in the transmission system for electricity is lawful. **The decision establishes a charging methodology which reflects** the impact that different classes of generators are anticipated to have on investment costs in terms of providing the infrastructure necessary to ensure demand at peak times is met and, **broadly, the impact that particular generators have on investment decisions taken to address constraints within the system**."[2]

2.6 The Proposer supports the Authority's decision to implement WACM2 and supports the Judicial Review Judgement that WACM2 does broadly reflect the "…impact that particular generators have on investment decisions taken to address constraints within the system." However, the proposer also notes that it remains possible to develop additional proposals to even further improve on the cost reflectivity of the charging methodology. To this end CMP268 Original proposal further improves the charging methodology as introduced by CMP213 WACM2 to even further improve its cost reflectivity with regard to the way the cost of constraints is reflected in respect to a particular special set of circumstances.

2.7 CMP268 Original proposal does not seek to change the ICRP Transport model, or the way the Year-Round tariff is calculated, therefore the set of locational tariffs produced by the Transport model are not affected. This Original proposal does not seek to change existing generator classifications as already defined within the charging methodology. This proposal also does not seek to change the methodology used to calculate diversity, or how this relates to the charges paid by Low Carbon, or Intermittent generators.

2.8 The only aspect which this Original proposal does seek to change is with regard to the tariff formula by which the existing Year-Round Not-Shared tariff element is applied to only the specific type of individual generator which the charging methodology currently defines as being classed simultaneously as both "Conventional" and "Carbon".

Proposer's description of the defect

2.9 The Proposer considers the current charging methodology fails to adequately reflect the fact that when the flows behind a boundary are dominated by low carbon generation, then different types of "Conventional" generation (e.g. low load factor peaking plant compared with higher load factor CCGTs, or Nuclear) cause different transmission network investment costs to be incurred due to their different network sharing characteristics.

2.10 The defect identified by this modification proposal relates to a type of generating plant which the existing charging methodology defines as being both "Conventional" and "Carbon". For the purpose of simplicity, this modification proposal refers to this group of generators as "Conventional Carbon". To aid understanding of the modification proposal, an explanation is provided in the section below and this "Conventional Carbon" generator type is highlighted in red in Table 1 below

[2] CMP213 Judgement

2.11 In the Proposer's view the defect is that there is a specific circumstance where the charging methodology is not cost reflective because it fails to recognise that Conventional Carbon plant does in fact continue to fully share all Year-Round circuit costs even in circumstances when the proportion of plant which is Low Carbon exceeds 50%. This is because Conventional Carbon generators tend to provide positive bid prices, so continue to provide a relatively low cost option for managing constraints irrespective of the concentration of low carbon generation behind a boundary.

2.12 The Proposer notes the defect in the current methodology delivers the result that "Conventional Carbon" plant in zones with a significant Not-Shared Year-Round tariff are charged TNUoS tariffs which are higher than the cost they cause and therefore the charging methodology is not cost-reflective in those specific circumstance for that type of plant.

2.13 The Proposer also considers within the current methodology, when the penetration of Low Carbon generators increases beyond 50%, the degree of sharing of Year-Round circuits is assumed to linearly reduce for all classes of generation. The current methodology therefore applies the TNUoS tariff elements to all "Conventional" generators in the same way irrespective of whether they are classed as "Carbon" (low constraint cost impact due to low BM bid cost), or "Low Carbon" (High constraint cost impact due to high BM bid cost). In the view of the Proposer this represents a defect because the ability of Conventional Carbon to share with Low Carbon plant actually <u>increases</u> as Low Carbon plant becomes more dominant. The existing charging methodology assumes exactly the opposite relationship and therefore provides incorrect and perverse locational incentives for Conventional Carbon generators within zones with a relatively high concentration of Low Carbon generators.

<u>Explaining the Status Quo on the Classifications of Generators.</u>

2.14 The Proposer notes that to understand this modification proposal, it is important to be clear regarding the following terms which have a specific technical definition within the existing charging methodology:

2.14.1 **Technology type by dispatchability:** Two classes of either "conventional" or "intermittent" depending on whether they can be dispatched as firm, or non-firm respectively.

2.14.2 **Technology type by bid price:** Two classes of either "carbon" or "low carbon" depending on whether they tend to exhibit low cost, or high cost balancing mechanism bid prices respectively due to their short-run marginal cost of generation.

2.15 The Proposer also notes that these two different sets each containing two different technology classes effectively combined to produce four different classification types. These four different types were created by CMP213 to enable TNUoS charges to better reflect the different costs to transmission network investment caused by different types of generator. The first classification type of "Conventional" versus "Intermittent" is used by the charging methodology to identify whether a generator can be dispatched on a firm basis, so identify whether or not it pays the Peak Security tariff element. The second classification type of "Carbon" versus "Low Carbon" is used by the charging methodology to adjust the degree of sharing by taking account of the level of diversity as defined by the concentration of "Low Carbon" generation. The table below describes the four potential plant classification combinations and also includes a list of which generation technology types are currently included within each category by the existing charging methodology:

		Technology type by bid price	
		"Carbon" (Assumed low cost BM bid price)	**"Low carbon"** (Assumed high cost BM bid price)
Technology type by dispatchability	**"Conventional"** (Firm dispatch, so pays Peak Security tariff)	**"Conventional Carbon":** CCGT, OCGT, Coal, pumped storage, CHP, biomass	**"Conventional Low Carbon":** Nuclear, hydro
	"Intermittent" (Not firm dispatch, so does not pay Peak Security tariff)	**"Intermittent Carbon"**: No technologies identified	**"Intermittent Low Carbon"**: Wind, PV, tidal, wave

Table 1: Technology type – dispatchability by bid price

2.16 Further detail regarding these four existing classification types is described below

2.16.1 Characterisation by dispatchability

- **"Conventional"** – Stations which are capable of dispatching on a firm basis to meet peak demand. These stations contribute to network flows within the ICRP Transport model Peak Security background, so these stations pay the Peak Security tariff element.

- **"Intermittent"** - Stations which are not capable of dispatching on a firm basis to meet peak demand because they are reliant on a weather dependent source of input energy. These stations do not contribute to network flows within the ICRP Transport model Peak Security background, so these stations do not pay the Peak Security tariff element.

2.16.2 Characterisation by bid price

- **"Carbon"** – This is the name used (for the purpose of CMP213) to identify a class of generating stations that comprises generation plant that is flexible in nature, can reduce/increase output driven by market price and transmission system needs and importantly has a material positive short run marginal cost. In practice all interconnectors and all transmission-connected storage are allocated by CMP213 into this category. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively low cost (positive bid price), so offering a relatively low cost solution to managing constraints.

- **"Low carbon"** - This is the name used (for the purpose of CMP213) to identify a class of generating stations with the purpose of including stations which tend to operate on a "must run" basis, so almost always generate when input energy is available or, for technical reasons are inflexible, irrespective of transmission system need; e.g. demand level. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively high cost (low or negative bid price), so offering a relatively high cost solution to managing constraints.

Carbon	Low Carbon
Coal	Wind
Gas	Hydro (excl. pumped storage)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

Table 13 – Classifications used for carbon vs. low carbon

Table 2: Classification used for carbon vs low carbon generation taken from CMP213 FMR

Baseline

2.17 Transmission licensees – both onshore and offshore – are required by their licences to comply with the National Electricity Transmission System Security and Quality of Supply Standards (NETS SQSS)[3], which sets out criteria and methodologies for planning and operating the GB Transmission System. This cost is then reflected by the TNUoS tariffs calculated according to the Investment Cost Reflective Pricing (ICRP) methodology using the Direct Current Load Flow (DCLF) Transport model. The SQSS was changed in 2011 to include the locational elements of the Security Background and the Economy Background. Then project TransmiT resulted in Ofgem reaching a decision regarding CMP213 which introduced changes to the ICRP charging methodology to reflect the new SQSS investment criteria by introducing the locational Peak Security tariff element and the locational Year-Round tariff elements.

Economic case for the Principle of the "ALF"

2.18 The Proposer provided extracts from the CMP213 Original proposal which he considered explained the economic rational regarding why it is cost reflective for TNUoS charges to reflect incremental constraint cost.

2.18.1 "As a greater proportion of variable, renewable generation connects to the transmission network, the output of many conventional generators has also

[3] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/The-SQSS/

become more variable in nature. As generators of different types change the way in which they use the transmission network, the nature of transmission capacity investment planning has also altered to ensure efficient investment is undertaken. **This is exemplified in the recent changes to the NETS SQSS (GSR-009) and the increasing amount of investment justified on the basis of avoided future constraint costs** (i.e. outside of the deterministic NETS SQSS standards). In order to maintain a consistent level of cost reflectivity, Transmission Network Use of System charges must also evolve to reflect these underlying physical changes."[4]

2.19 The Proposer noted the requirement within the NETS SQSS for the Main Interconnected Transmission System (MITS) to meet the Economy Criteria is described below:

> "The *MITS* shall meet the criteria set out in paragraphs 4.5 to 4.6 under both the Security and **Economy background** conditions"[5]

2.20 The Proposer highlighted the Authority Decision regarding GSR009[6] which he considers explains the economic reason for the introduction of the Economy Criterion into the NETS SQSS as described below:

> "GSR009 proposes a 'dual criteria' approach to assessing required capacity which would take into account both demand security and economic efficiency when developing the transmission network.
>
> "An Economy Criterion which requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The approach involves a set of deterministic parameters which have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an **appropriate balance between the constraint costs and the costs of transmission reinforcements.** The assumptions in the generic or pseudo CBA would be reviewed every five years."

2.21 The Proposer highlighted that the CMP213 Original proposal went on to explain why the inclusion of an Annual Load Factor (ALF) to the TNUoS charging formula would result in TNUoS charges which are more cost reflective:

> "Explicit commercial arrangements are not in place that provide Transmission Licensees with information to assess the impact on the need for transmission network investment arising from an individual generator when planning investment. Therefore implicit assumptions over input prices (fuel, CO2, subsidy, etc.) and generator characteristics (efficiency, availability, etc.) relative to the remainder of the market are made. In order to remain cost-reflective, any proposed scaling factor needs to be reflective of the implicit

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[4] **CMP213 Original CUSC Modification Proposal "Project TransmiT TNUoS Developments" (National Grid, 20/06/2012).** http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

[5] NETS Security and Quality of Supply Standard Issue 2.2 – 5 March 2012 - Current. http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/The-SQSS/

[6] National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS): Minimum transmission capacity requirements (GSR009). http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/SQSS/Modifications/Concluded/

assumptions made when planning network capacity. **This proposal puts forward a form of generator specific annual load factor, based on 5 years historic output, as representative of the assumptions made when planning investment and achieving an appropriate balance between simplicity and cost-reflectivity In order to maintain what is deemed to be an appropriate balance it is proposed that the annual load factor be applied in an equal manner across all wider TNUoS zones regardless of generation plant mix**

2.22 The Proposer noted the Authority decision[7] regarding CMP213 was to implement the Workgroup Alternative Modification Proposal 2 (WACM2).

2.22.1 "Following careful consideration of the evidence, including all the consultation responses, we find that our minded-to option set out in August 2013 and April 2014 is **more cost reflective than the current methodology and best meets our statutory duties**. We have therefore decided to approve this option for implementation in April 2016. We announced our decision on 11 July 2014 and this document sets out our reasoning."

2.23 The Proposer highlighted that there would also be two further adjustments to the Year-Round tariff. The first of these is to split the tariff into two elements: 'shared' and 'non-shared.' This refers to generators' ability to 'share' transmission capacity which depends on the concentration of types of generators in a particular area. It recognises that it is efficient to build more transmission capacity for areas with a high concentration of low carbon generation because **this type of plant** is likely to be generating at the same time (i.e. when the wind blows) and **is expensive to constrain off**.

2.24 The second adjustment is to adjust the 'shared' element of the Year-Round tariff by a generator's average annual load factor for the last five years (with the highest and lowest years discarded). **This recognises that there is a link between the level of constraint costs triggered by a generator and the level of transmission investment**.

<u>The element of the current tariff formula CMP268 proposes to change</u>

2.25 The Proposer noted when the percentage of low carbon plant behind a boundary increases above 50%, the current methodology assumes a straight line reduction in the degree of sharing from 50% until the proportion of load flow on the circuit accounted for "Carbon" plant declines to 0%. This is illustrated in the graph below.

[7] Project TransmiT: Decision on proposals to change the electricity transmission charging Methodology, Ofgem 25 July 2014. http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

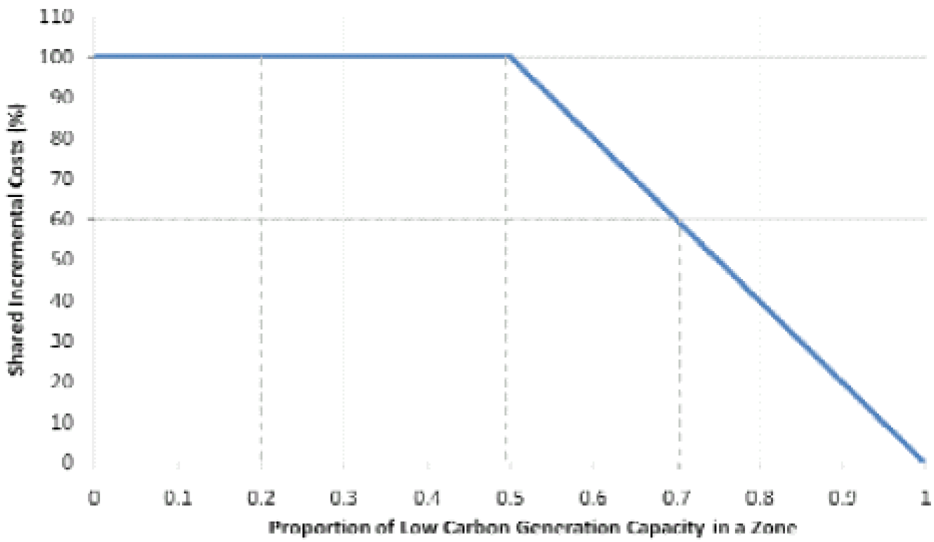


Figure 1: Taken from "Figure 18" from the CMP213 Workgroup Final report.

2.26 The Proposer highlighted that this principle is enacted through the current formula within the charging methodology where all generators (including Conventional Carbon generators) have their ALF applied to their Shared Year-Round tariff element, while also for <u>all types of generator</u>, their ALF is not applied to their Not-Shared Year-Round tariff element. This is illustrated for Conventional Generators by the formula below in Figure 2 taken from National Grid published Final TNUoS tariffs for 2016/17.

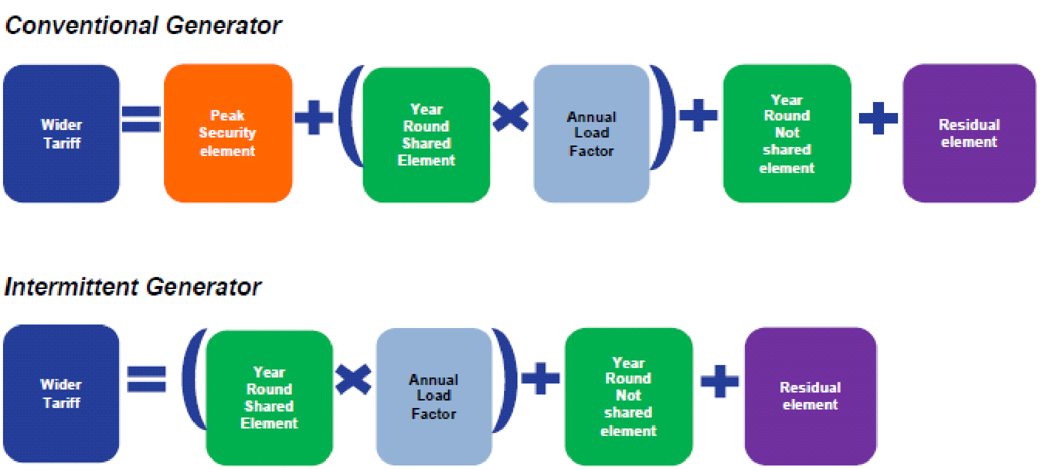


Figure 2: Charging Methodology

<u>Purpose of the proposal</u>

2.27 The Proposal is that the charging methodology should be changed to more appropriately recognise that the different types of “Conventional” generation (those classed as “carbon” compared with those classed as “low carbon”) do cause different transmission network investment costs, which should be reflected in the TNUoS charges that these different types of “Conventional” generation pays.

2.28 The Proposer asserts that change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator’s ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements.

Proposed change to TNUoS tariff formula

2.29 The Proposer states this modification proposes a change to the tariff formula relating to the way sharing is applied to Conventional Carbon generators so they continue to obtain 100% sharing of incremental costs irrespective of the proportion of low carbon generation capacity in a zone. This is illustrated by the graph below, which is a modified version of “Figure 1” above.

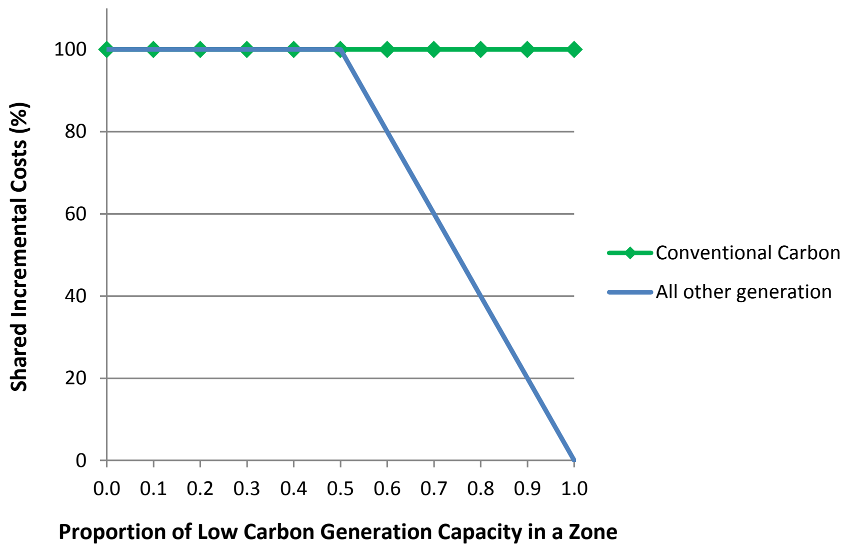
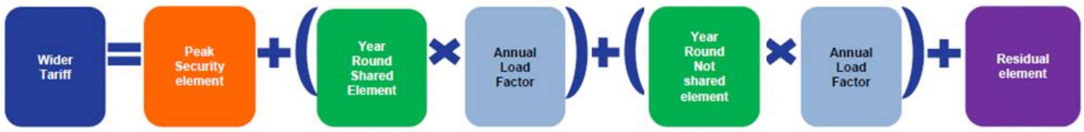


Figure 3: Proposed change - Modified Figure 1

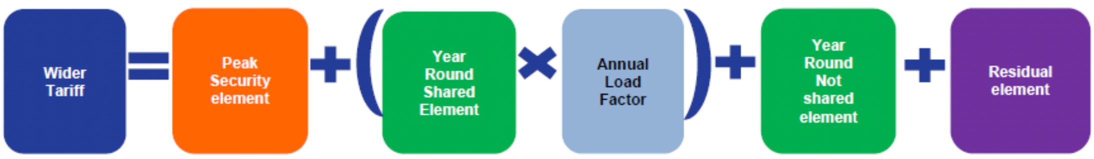
2.30 The Proposer highlights that this modification proposal will recognise that even when the proportion of “Low Carbon” plant influencing a boundary is close to 100%, then it is more cost reflective that conventional carbon plant should have its ALF applied to the whole Year-Round tariff (both Shared and Not-Shared elements of Year-Round).

2.31 The Proposer states that this will require a change to the existing tariff formula which currently relates to “Conventional Generator” by splitting it into two: firstly the new tariff formula relating to “Conventional Generator – Carbon” and secondly unchanged existing tariff formula which will continue to apply to “Conventional Generator - Low Carbon”. For the avoidance of doubt, the existing tariff formula relating to “Intermittent Generator” is also unchanged by this modification proposal. The proposed new tariff calculation formulas are illustrated below:

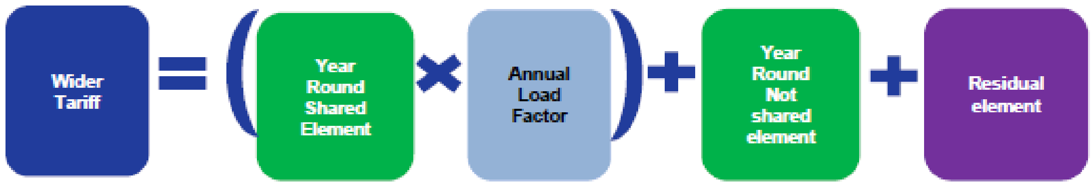
2.31.1 ***Adjusted tariff formula: “Conventional Generator – Carbon”*** - This represents a change from the existing “Conventional Generator” tariff formula since it applies the Generator’s ALF to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements.



2.31.2 ***Unchanged tariff formula: “Conventional Generator – Low carbon” -*** The tariff calculation remains the same as the current “Conventional Generator” tariff. It would be appropriate to give this unchanged tariff formula a new name to ensure it is clear which types of generation this applies to.



2.31.3 ***Unchanged tariff formula: “Intermittent” -*** For the avoidance of doubt, the tariff formula currently used by the baseline for “Intermittent” generators is not affected by this modification proposal and remains unchanged as per the formula below.



2.32 It is proposed that this new tariff calculation methodology would apply from the TNUoS charging year starting April 2017.

3 The Proposers Presentation

Economic rationale behind network sharing

3.1 The proposer presented extracts from the CMP213 Final Workgroup Report Sections 4.19 to 4.20 in which the report explained a key principles which determine the degree of sharing including:

"The [CMP213] Workgroup agreed that annual incremental constraint costs for each generator with a given TEC (i.e. £/MW/annum) are comprised of two main components, illustrated below in Figure 5 which could be further sub-divided into five variables." (CMP213 Final Workgroup Report 4.19)

The proposer presented the following figure which the CMP213 Final Workgroup report used to illustrate this principle:

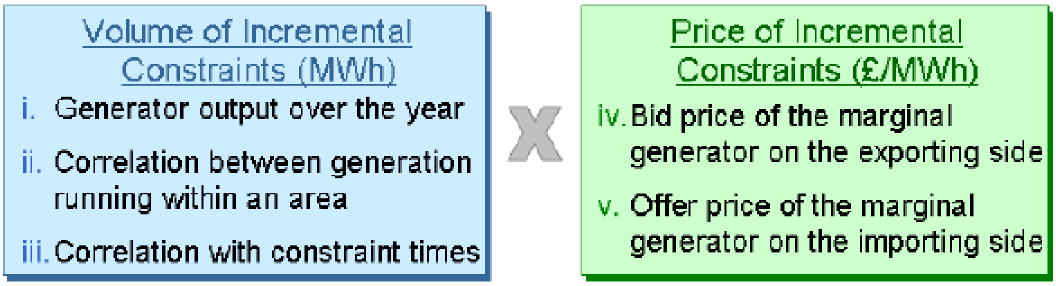


Figure 5 – Components that drive transmission constraint costs

3.2 The proposer presented the case that these are the key principles regarding why a Conventional Carbon generator is able to fully share all Year Round circuits irrespective of the penetration of low carbon plant behind a network boundary. The proposer suggested these principles are consistent with the greater detail regarding sharing which can be found in the CMP213 Final Workgroup Report Volume 2, Annex 4, Sharing.

3.3 The proposer explained these factors in the context of an OCGT as an example of a carbon emitting low load factor peaking plant in the following way.:

- **Generator output over the year** – The proposer suggested that if a generator does not generate at all, then it does not cause any change in Year Round circuit flows so it does cause any change in the required investment in transmission network required to manage constraints. A higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this relationship.

- **Correlation between generation running in an area – The proposer suggested that a**n OCGT will tend to only dispatch in periods when wholesale power prices are relatively high, which will also tend to be correlated with periods when generation from low carbon plant is relatively low, therefore their generation will tend to be counter correlated. A third variable can affect this correlation such as cold wintery weather because the associated high demand conditions may enable conventional carbon to generate to earn high wholesale power prices at the same time as relatively high wind conditions without causing constraints. A higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this relationship.

- **Correlation with constraint times** – The proposer suggested that is the most important of the three volume related criteria. An OCGT is unlikely to be generating during periods when constraints occur. This is because periods of constraint tend to be associated with periods of relatively high output from low carbon generation occurring simultaneously with relatively low levels of demand. Therefore constraints are most likely to occur during periods of relatively low wholesale power prices during which it is highly unlikely that an OCGT would choose to be generating. A higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this relationship.

- **Bid price of the marginal generator of the exporting side** – The proposer suggested that Conventional generation is low cost to bid off to manage constraints because they have a substantial positive avoidable cost. A higher penetration (beyond 50%) of low carbon generation in an area does not change this relationship.

- **Offer price of the marginal generator on the importing side** – The proposer suggested that the short run avoidable cost of conventional carbon generators is driven by their cost of fuel which is similar for different stations of the same type. This means that that there is a relatively low cost to the SO of managing constraints by bidding off one carbon emitting generator and replacing it with a different carbon emitting generator. The proposer suggested that a higher penetration (e.g. greater than 50%) of low carbon generation in an area does not change this effect because the cost to the SO of managing a constraint by bidding off conventional carbon plant is entirely independent of whatever bid prices low carbon generators in the same area may exhibit.

Evidence – Additional analysis presented in the CMP213 Final Workgroup Report Volume 2 Annex

3.4 The proposer presented evidence extracted from the CMP213 Final Workgroup Report Volume 2 Annex sections 4.14 to 4.26. This evidence includes the results of market modelling by National Grid using the ELSI model which the proposer suggested appears to indicate that when sharing occurs, the incremental cost can be reflected a generator’s ALF.

3.5 The proposer suggested that Conventional Carbon generators do continue to share even with a high proportion of low carbon generation (50% to 100% low carbon), so the network investment cost caused by Conventional Carbon generators should continue to be reflected by the “theoretical perfect relationship” as reflected by the current methodology through the use of the ALF.

Results from this ELSI model analysis which were presented to the Workgroup are illustrated with the figures below.

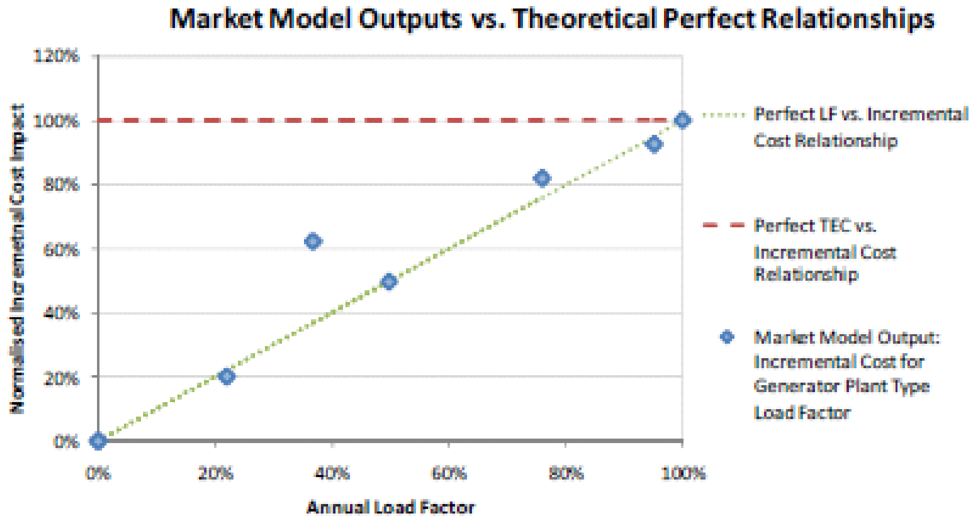


Figure 1 – Market Model Outputs vs. Theoretical Perfect Relationships

The CMP213 Workgroup carried out additional analysis using the ELSI model and the following figure was included in the CMP213 Final Workgroup Report Volume 2 Annex.

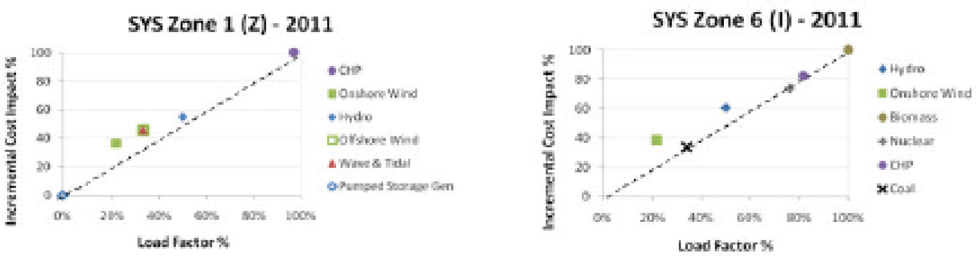


Figure 2 – Example ELSI analysis

<u>**Circumstances where sharing is reduced**</u>

3.6 The proposer described an extract from the CMP213 Final Workgroup Report Volume 2 Annex (4.111 to 4.118) which describes the potential causes which may cause sharing to break down.

3.7 The proposer interpreted this section of the CMP213 Workgroup Report as describing that as long as conventional carbon generation is available for the SO to constrain off, then sharing will continue to take place, while by contrast, sharing only breaks down when conventional carbon generation is no longer available. The proposer suggested that it logically follows that conventional carbon generators do not cause any reduction in sharing, but instead it is the absence of conventional Carbon generation which causes the reduction in sharing.

3.8 The proposer suggested that core principle of cost reflectivity is that generators should be exposed to price signals which reflect the cost that they cause. It follows that because conventional carbon generators do not cause sharing to break down, it is not cost reflective to charge them as if they do. Therefore, while it may be appropriate to charge the Not Shared Year Round tariff element at 100% of TEC to Low Carbon generators (on the reasoning that they do cause sharing to break down), it is not appropriate to charge the Not Shared Year Round element of the tariff at 100% of TEC to Conventional Carbon generators because they do not cause sharing to break down. The commentary I the CMP213 Workgroup Report Volume 2 Annex 4.118 explained that this illustrated the principle that the incremental constraint cost caused by Conventional Carbon generators remained reflected by the "theoretically perfect" red dotted line even if the penetration of Low Carbon generation exceeded 50%.

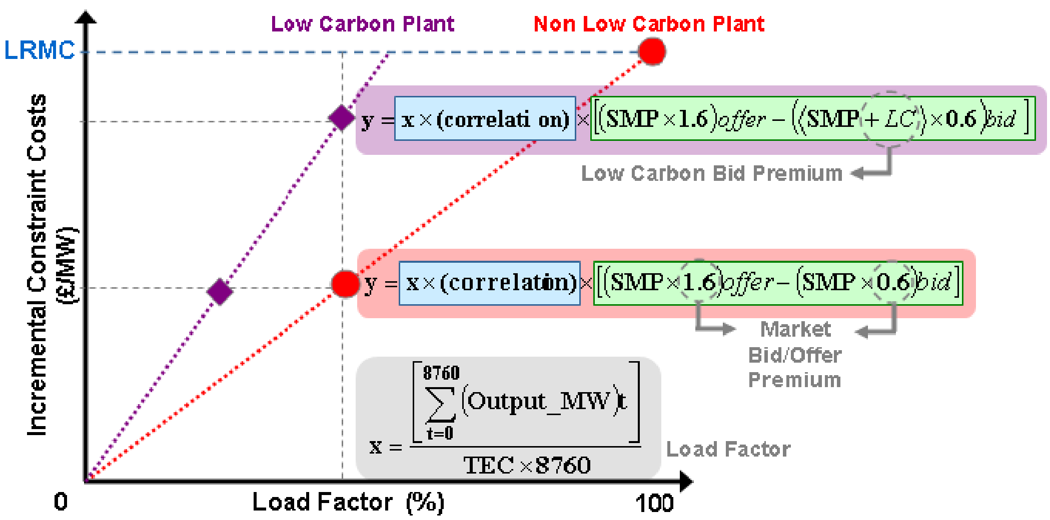


Figure 21 – Combined effect of price and load factor on constraint costs

<u>**Evidence – Simplified two node model**</u>

3.9 **Simplified two node model appears to indicate that that when sharing breaks down, it applies differently to different types of generator**

The proposer presented to the CMP213 Workgroup which used a simplified two node model to illustrate sharing. The proposer interpreted the CMP213 Workgroup report as representing evidence that Carbon plant continues to share network costs even in circumstances where Low Carbon plant may not. Therefore in circumstances when sharing breaks down, it should apply differently to different types of generator

3.10 The graph below is a result of this simplified two node economic model. The red dotted line was described as being consistent with full sharing, therefore circumstances where it is appropriate to apply the station's ALF to their Year Round tariff. The example described that further the penetration of low carbon extended beyond 50%, then the incremental cost of constraints becomes increasingly different between low carbon and carbon generation. The proposer interpreted that the analysis showed that higher penetrations of low carbon are associated with progressively lower cost of constraints caused by conventional carbon and conversely it is only the low carbon generation which is causing the higher cost of constraints.

3.11 The proposer suggested that this result would imply that it would be more cost reflective for the Year Round TNUoS charge paid by Conventional Carbon generators to become progressively lower as the penetration of wind increases. By contrast, the existing CMP213 WACM2 methodology provides the opposite result by applying progressively higher by charging 100% of TEC on the Not Shared Year Round tariff as if the Carbon generation was causing a reduction in sharing.

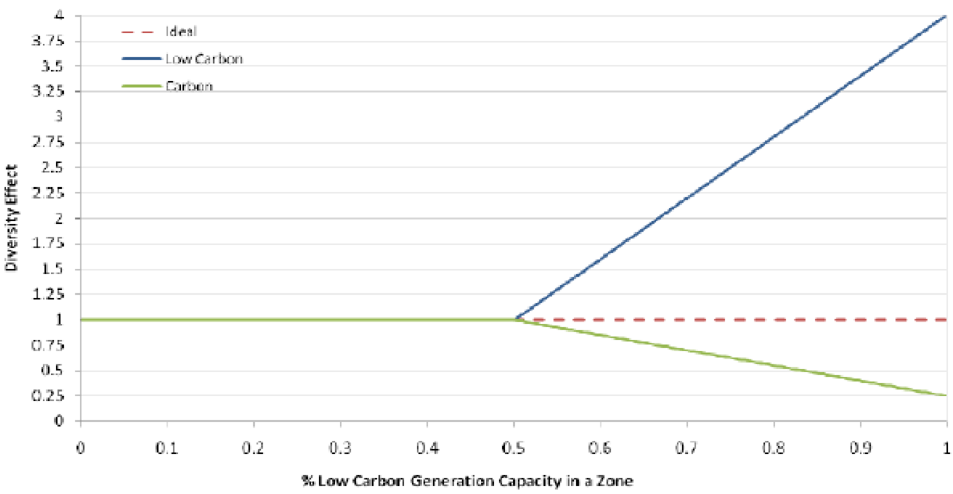


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

Evidence – Simplified two node model

3.12 The proposer presented a summary of evidence from ELSI modelling carried out by National Grid and previously presented to the CMP213 Workgroup.

3.13 The proposer suggested that this ELSI analysis further demonstrated that Conventional Carbon plant in SYS Zone 1 (Z) continue to fully share Year Round circuits even when flows behind a boundary are dominated by Low Carbon generation. The graphs above appear to demonstrate that when moving from a 2011 scenario to a 2020 scenario for SYS Zone 1 (Z), plant which the methodology defines as Conventional Carbon (in this example pumped storage generation and CHP) remain close to the idealized 100% sharing line in both 2011 and 2020. This means that these types of generators continue to fully share the year round circuits, so the constraint cost, therefore network investment cost which they cause continues to be proportional to their ALF even as the penetration of wind increases.

3.14 Further to this, the proposer suggested that the analysis also shows that CHP demonstrates a reduction in its incremental cost impact as it moves from above the idealised line in 2011 to below the idealised line following the increase in low carbon generation in 2020. The proposer suggested this further supports the position that as more wind is added to the system; the sharing benefit of the CHP has improved, not become worse.

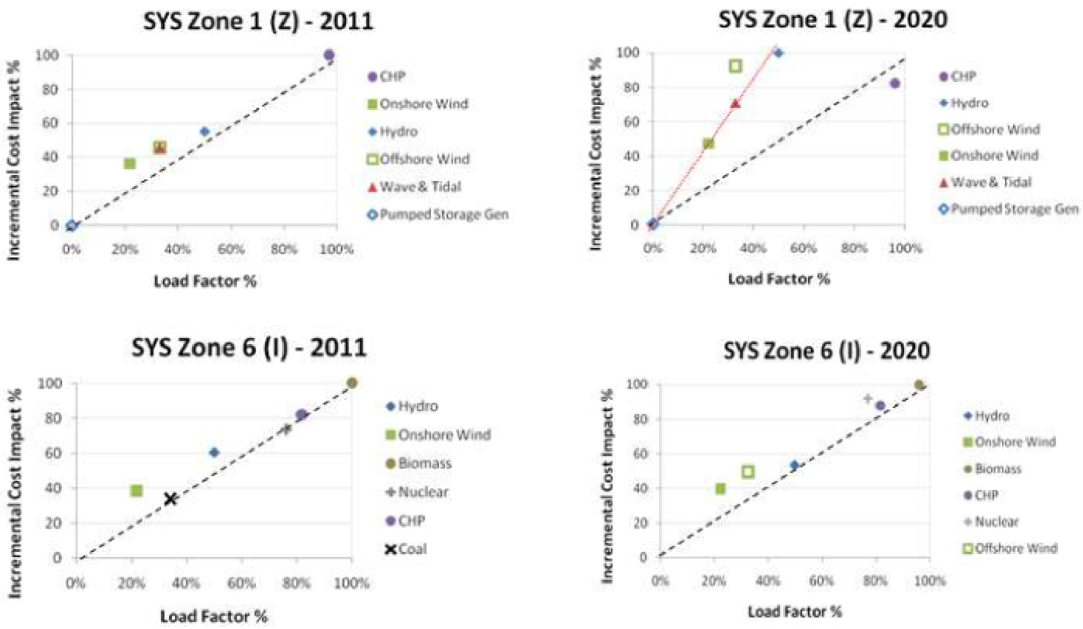
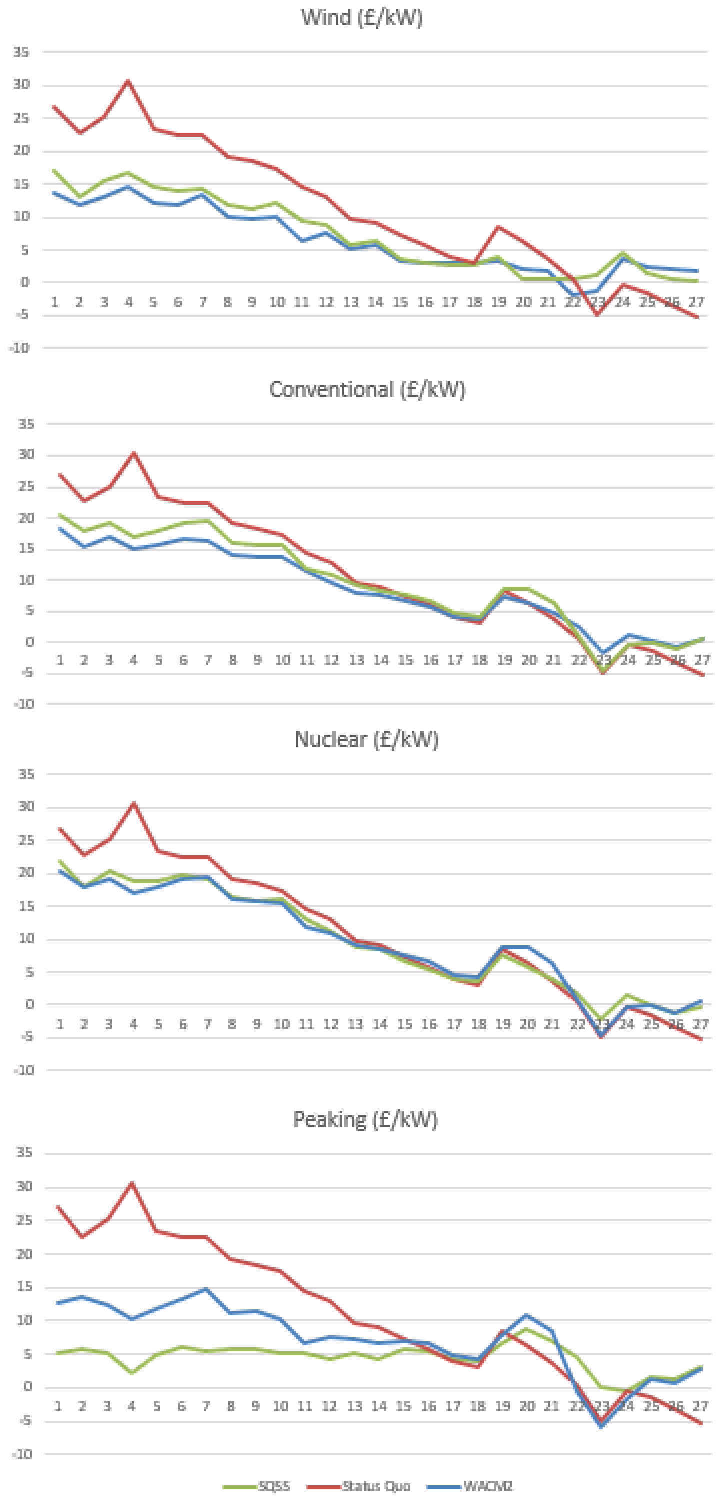


Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

<u>Evidence Cost reflectivity compared with SQSS</u>

3.15 The proposer presented a comparison of TNUoS charges compared with SQSS which was carried our by P E Baker. The proposer explained that this evidence can be interpreted as demonstrating CMP213 WACM2 may be over charging Conventional Carbon generators located in zones dominated by low carbon generation.

3.16 P E Baker published a report procured by SSE which carried out a comparison of [CMP213] WACM2 and Status Quo zonal charges in how they differ from costs implied by the SQSS.[8] The results of this are illustrated in the graphs below.



3.17 The proposer suggested that the following conclusions can be drawn from this analysis for different types of generator. The analysis appears to show that the CMP213 WACM2 is cost reflective of the SQSS scaling factors for most types of generator in most circumstances with the exception of low load factor Conventional Carbon plant in zones dominated by Low Carbon generation. Compared with the charges indicated by the SQSS, CMP213 WACM2 appears to charge too much to peaking plant with positive Year Round Not Shared tariffs in Scotland while it appears to charge too little for peaking plant in specific southern zones where there is a negative Not Shared Year Round tariff. The proposer suggested that these isolated examples where CMP213 WACM2 charges are furthest from being cost reflective of the SQSS are the particular examples where this CMP268 would result in an improvement in cost reflectivity so that TNUoS charges better reflected the SQSS.

Alternative modelling of cost reflectivity

3.18 The proposer presented simplified two node model produced by P E Baker suggesting that CMP213 WACM2 may be over charging Conventional Carbon generators located in zones dominated by low carbon generation.

The proposer suggested that this analysis demonstrated that as the penetration of wind increases, the ability of Conventional Carbon generation to share with wind increase therefore the investment cost caused by that Conventional Carbon plant reduces as illustrated by the downward sloping solid blue line in the graph above. The proposer suggested that this further supports the position that it is not cost reflective for the CMP213 WACM2 methodology to apply increasingly higher tariffs TNUoS tariffs for Conventional Carbon generators when the penetration of wind increases.

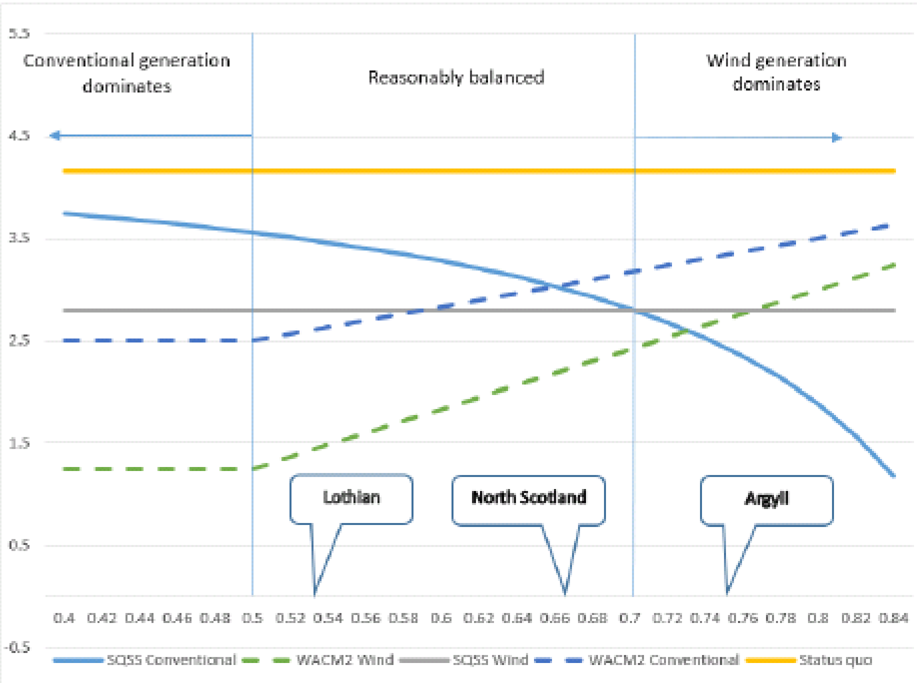


Figure 4. Variation of SQSS costs (£/kW) and WACM2 & Status Quo charges (£/kW) with sharing

Evidence from NERA/Imperial for RWE – Cost reflectivity Vs LRMC

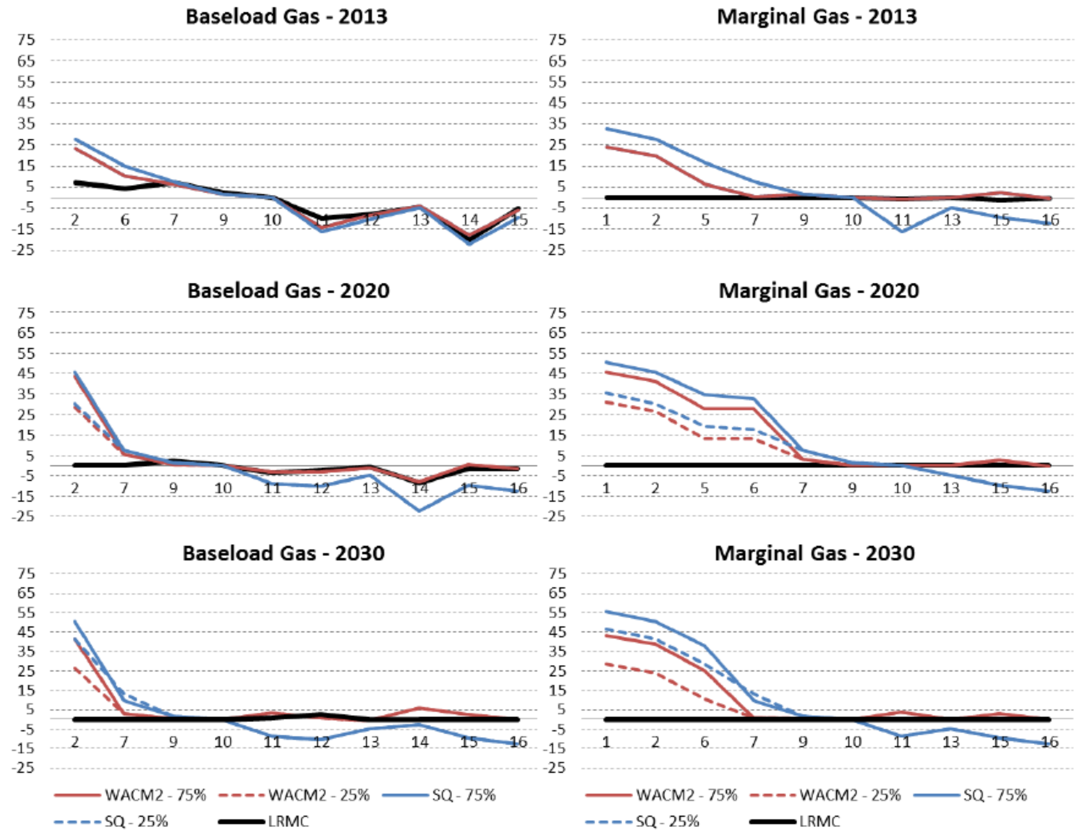
3.19 The proposer presented evidence showing a comparison with Long-run marginal cost modelling produced by NEAR/Imperial suggesting that CMP213 WACM2 may be over charging Conventional Carbon generators located in zones dominated by low carbon generation.

3.20 The proposer described that RWE procured analysis from NERA/ICL, resulting in the report Assessing the Cost Reflectivity of Alternative TNUoS Methodologies (February 2014)[9] which compared the TNUoS tariffs derived from the pre April 2016 Status Quo charging methodology and those provided by the CMP213 WACM2 methodology with an analysis of Long Run Marginal Cost (LRMC) caused by different types of generating station.

3.21 The proposer highlighted that they viewed there were many shortcomings with the approach taken by this NERA/Imperial analysis. However this report did appear to further support the proposer's position that the CMP213 WACM2 is cost reflective for most types of generator in most locations with the particular exception of Conventional Carbon plant in zones dominated by Low Carbon generators. The proposer further emphasized that the CMP268 proposal would enable the TNUoS charging methodology to improve its cost reflectivity in those specific cases, while maintaining the existing cost reflectivity for other types of generator in other locations unchanged.

3.22 The proposer presented a summary of the analysis as represented by the graphs below.

Figure 5.4
TNUoS vs. LRMC for Gas Capacity (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

Evidence from Poyry for Centrica

3.23 The proposer presented an extract from a report produced by Poyry regarding specific circumstances where CMP213 may provide a perverse price signal which could put regional security of supply at risk. The proposer presented the quote from Poyry as follows:

> "Consider a two zone system, there the smaller zone, A consists almost entirely of wind capacity – say 9.5GW of wind and 0.5GW of inefficient OCGT (a small bit of nuclear/hydro/pumped storage doesn't change this example much). Under Diversity 1, there would be almost no sharing assumed, and the zone would be an importer for the peak component, so have a negative peak charge. However, **with almost no sharing an OCGT would pay nearly as much for the year round as the wind (or indeed a nuclear plant if there was one). However, the OCGT wouldn't run in practice unless the wind output was low – consequently it is very unfair that it should have to pay high year-round charges**. Indeed, in this example zone A would be a very good location for an OCGT (as the negative peak charge would signify a strong need for generation capacity). **Whilst this may or may not offset the inappropriate year round tariff – the key point is that for a high wind zone the CMP213 year round tariff is not cost reflective and over-allocates cost to the non-wind generation in the zone.** (Poyry 3.2.1.4)

3.24 The proposer suggested that this analysis by Poyry is a helpful description of the specific circumstances where the proposed defect in the CMP213 WACM2 methodology is most apparent and it is this situation where the cost reflectivity of TNUoS charges would be most improved following the implementation of CMP268.

Cost Reflectivity

3.25 The proposer suggested a key test of the modification proposal is whether it is more cost reflective and this question should be considered in the context of three key elements of transmission network investment and charging, namely: 1) The NETS SQSS Economy Criteria. 2) A Cost Benefit Analysis and 3) TNUoS charging methodology. The proposer suggested that these three parts are different from each other because they are used for different purposes, however, they should all be cost reflective of each other as far as practicable. The proposer described relevant features of these three in the context of this modification using the illustrative example of an OCGT:

3.26 NETS SQSS – The proposer noted that modification CMP268 focuses on the TNUoS Year Round background, so the relevant part of the SQSS to compare its cost reflectivity with is the Economy Criteria. The proposer noted that the SQSS Economy Criteria assumes a zero scaling factor for an OCGT. The proposer suggested that this means that in terms of the SQSS, an OCGT does not contribute any cost to network investment within the Economy Criteria irrespective of whether or not flows behind a boundary may be dominated by low carbon generation. The proposer suggested that, therefore to be cost reflective of the SQSS, then the TNUoS Year Round charge (both shared and not shared) for an OCGT should also be zero irrespective of whether or not flows behind a boundary may be dominated by low carbon generation (assuming the OCGT has an ALF of zero).

3.27 Cost Benefit Analysis – The proposer noted that a key tool used in a cost benefit analysis is the National Grid ELSI model. The proposer described that the ELSI model uses as inputs assumptions regarding the cost of fuel of individual stations, from which the model derives generation performance and values of network constraint costs. The proposer suggested that within the ELSI model, an OCGT with a very high cost of fuel would tend exhibit little, or no generation volume, which would imply that in terms of a cost benefit analysis, an OCGT does not contribute any cost to network investment for the purpose of managing constraints within the ELSI model. The proposer suggested that to be cost reflective of a cost benefit analysis, then the TNUoS Year Round charge for an OCGT (both shared and not shared) should also be zero (assuming the OCGT has a zero ALF). This result is also consistent with and cost reflective of the SQSS Economy Criteria as described above.

3.28 TNUoS charging methodology (baseline) – The proposer observed that the baseline CMP213 WACM2 charging methodology can provide a very different result from the SQSS and a Cost Benefit Analysis because an OCGT with a zero load factor may be exposed to a very high TNUoS charge if it is located in a zone with a substantial Not Shared Year Round tariff. The proposer suggested that the conclusion could be drawn that with regard to a zero load factor OCGT in a zone dominated by low carbon generation, the baseline TNUoS charging methodology is not cost reflective of either the SQSS Economy Criteria, or a cost benefit analysis.

3.29 The proposer suggested that the change to the tariff methodology proposed by CMP268 which would apply an OCGT's ALF to all Year Round tariffs (both shared and not shared) would result in a combined Year Round charge for that OCGT of close to zero (assuming an ALF of close to zero) in all circumstances. The proposer suggested this means compared with baseline, CMP268 would result in a TNUoS charge for an OCGT which is more cost reflective of both the SQSS and more cost reflective of a cost benefit analysis.

3.30 The proposer suggested that this result of better cost reflectivity can be generalized to other types of generator. The proposer suggested that the result for an OCGT of the zero scaling factor within the SQSS Economy Criteria and zero (or close to zero) generation within the ELSI model can be generalized to any Conventional Carbon generator which also exhibits a zero, or close to zero load factor. The proposer suggested this result is illustrated in the sample ELSI results from CMP213 which the proposer presented to the Workgroup, which shows a Pumped Hydro generator with an apparently zero load factor associated with an apparently zero cost of incremental constraint. The proposer suggested a conclusion could be drawn that the modification CMP268 would be more cost reflective that the baseline for any type of very low load factor Conventional Carbon generator.

3.31 The proposer suggested this result could be further generalized to demonstrate that CMP268 would be more cost reflective for all Conventional Carbon generators in zones with a non-zero Not Shared Year Round tariff irrespective of that generator's ALF. The proposer suggested this could be understood by considering a theoretical 100% load factor CCGT, because in this situation modification CMP268 would result in exactly the same Year Round TNUoS charge as the baseline, therefore in this situation, CMP28 would be as cost reflective as the baseline. The proposer suggested that if, CMP268 is as cost reflective as baseline for a 100% ALF Conventional Carbon generator and more cost reflective than baseline for a 0% load factor, then CMP268 could be expected to also be more cost reflective for Conventional Carbon generators with an ALF anywhere between the two (between 0% and 100%).

4 Workgroup Discussions

4.1 This section is representative of the views of the Workgroup. These discussions have been summarised into five key areas.

1) CMP213 Analysis
    - Effect on tariffs and impact on cost reflectivity of ALF
2) Distributional Impact
3) HVDC Impact
4) Impact on Customer (indirect impact and regional security of supply impact)

It needs to be noted that this discussed followed on from the content presented above by the proposer. This evidence was made available to the Workgroup prior to inform Workgroup discussion. The reason that the proposer's background and presentation has been presented separately is due to the limited scope of the defect and time constraints rendering it difficult to cover all topics in great detail in the Workgroup discussions.

1) <u>CMP213 Analysis</u>

4.2 Workgroup members felt that the urgent timescales granted to the modification meant that opening up all of analysis carried out by CMP213 was not possible. It was concluded that when Ofgem approved WACM2, Method 1 in the decision letter of CMP213 it advocated this as the most cost reflective option. As a result, the Workgroup decided that the scope of CMP268 needed to only determine whether the proposal better improved the cost reflectivity of the current baseline. The Ofgem decision letter can be accessed using the link below and be found in the 'Ofgem Decision' tab:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

4.3 The Workgroup acknowledges that the CUSC Panel have noted that existing analysis collated as evidence to for CMP213 could also be used to support CMP268 however the urgent timescales associated with this modification would not permit the refresh of any of this data.

4.4 Due to the urgent timescale to deliver the modification, the Proposer provided some supporting analysis to the Workgroup which he believes supports his proposal which is detailed in the proposers presentation section. The Proposer suggested that the information indicated that constraint costs across a zone were a function of the amount of carbon and low carbon generation, and that low carbon generation increasingly drove the cost of constraint rather than low load factor carbon generation.

4.5 A workgroup member suggested that given the urgent timescales for consideration of the modification proposal it was not possible to evaluate fully all of the evidence regarding sharing provided under Chapter 4 of the CMP213 Workgroup and in the Appendices to this report (Volume 2). The Workgroup member indicated that the alternative approaches to sharing that were presented in this report were effectively out of scope (e.g. using scaling factor or different diversity options). The Workgroup member suggested that the key issue for consideration was whether there was a case for sharing the non-shared component of the tariff under the current baseline (CMP213 WACM2). Therefore the evaluation should concentrate on method 1 in the CMP213 Workgroup report and the arguments presented by the CMP213 Workgroup with respect to this option.

4.6 The Workgroup considered the case that was made under the Method 1 approach under CMP213. It was highlighted that the key features of this approach included an acceptance that carbon and low carbon could drive transmission investment on a shared basis up to a 50% sharing factor of carbon and low carbon. This was achieved by applying a load factor (ALF) to the shared component of the tariff. Thereafter, the non-shared component of the tariff was applied to the TEC of generation within the zone, recognising that the capacity of generation was the key factor driving investment for the non-shared elements of transmission investment.

4.7 A Workgroup noted in their view that the CMP213 Workgroup report, flagged some members of the CMP213 Workgroup were concerned that “small volumes of carbon in a predominantly low-carbon area would not be adequately recognised under this option” (para 4.70) which highlights the issue raised in modification proposal CMP268. However, when compared with the pre-CMP213 Baseline, it was noted that some members of the CMP213 Workgroup believed that method 1 was a “better reflection of how the system was planned and so was more cost reflective overall” (para 4.72). In this context a Workgroup member requested that National Grid should consider whether the approach under CMP213 WACM2 better reflected transmission investment planning decisions when compared with CMP268.

4.8 The Workgroup noted that in making their decision the Authority recognised that “the assumption through use of ALF in WACM2 of a perfectly linear relationship between output and constraints is therefore a simplification” (Ofgem decision and CMP213, para 2.15, page 14). However, the Authority also noted that the WACM2 approach “represents a simple, transparent proxy for the impact of a generator on constraint costs, and therefore on transmission investment, taking into account the mix of generation in an area” (Para2.17. In addition, the Authority noted that “it will not precisely reflect the impact that a generator has on transmission investment in every circumstance, especially in the extremes, for example, where there is 0% or 100% of a particular type of generator in a zone” (para 2.17).

4.9 The Workgroup discussed the nature of the sharing of the non-shared component of the tariff. The proposer believes that the current methodology does not properly reflect the costs of individual generators on sharing within a zone and was therefore not cost reflective for that generator with respect to the application of the non-shared component of the tariff. The proposer highlighted that in zones that were dominated by low carbon generation, it was these generators that were driving the costs of constraints.

4.10 One Workgroup member argued that with respect to the non-shared component it was all generation (carbon and low carbon) in a zone that was considered to be responsible for the transmission investment driver under the CMP213 WACM2 approach and not exclusively the low carbon generation. This reflects the fact that the tariff model is zonal rather than nodal in nature. Consequently it is cost reflective for all generators within the zone to face the non-shared component of the tariff.

4.11 It was noted by one Workgroup member that under the current baseline (CMP213 WACM2) low load factor carbon generation has a significant discount with respect to the overall Year-Round tariff. These generators currently pay the shared component based on the ALF (which would be a low cost for low load factor plant) and only pay the shared component with respect to TEC. This discount provided cost reflective marginal signals for generators in that zone based on the CMP213 WACM2 approach.

4.12 In discussing the investment drivers a Workgroup member noted that the cost of constraints and the type of plant was historically a use for concern with a risk that certain plant could have locational market power. However, it was noted by the Workgroup that the Transmission Constraint Licence Condition now in force should substantially remove the potential for market power in such circumstances.

4.13 This Workgroup member said that in their understanding of System Operations, this supposition seemed unlikely to be accurate in practice; when there is high wind output in such areas (and thus to a degree nationally), the lack of “inertia” from wind may mean that National Grid takes steps to ensure that more of the carbon type plant is running nationally, including in these areas.

4.14 They also noted that another reason why National Grid may require output from the carbon plant in these areas, even at times of high low carbon generation there, for reasons of voltage or stability support, due to their good characteristics from a System Operator point of view, unrelated to local energy balance or thermal circuit limits.

4.15 The Workgroup member furnished the Workgroup with a graph of data (Figure 4) from every half hour in 2015 that they believe bears out this supposition, as well as circulating the underlying data/spreadsheet. They noted that by bundling the generation data points into deciles by wind output, what appears to be the very relationship that was conjectured is seen. They used data for the metered data from a representative sample of 6 Scottish generators (as visible in central systems), namely Areleoch, Blacklaw, Harestanes, Clyde, Griffin, and Hadyard Hill, choosing this area as they considered it to be the most marked case of an export-constrained area with more than half renewable capacity. They also noted that in the windiest 10% of hours (Decile 10, the right-most bar below), the output from the Scottish pumped storage stations (green) and Peterhead (blue) are both significantly higher than in the least windy 10% of hours, indeed higher than in any other decile in-between”. The analysis was not extended due to lack of time to other areas with relevant conventional carbon assets and a non-zero non-shared generation TNUoS charge elements such as the Northern English TNUOS charging zones down to zone 15, or zone 22.

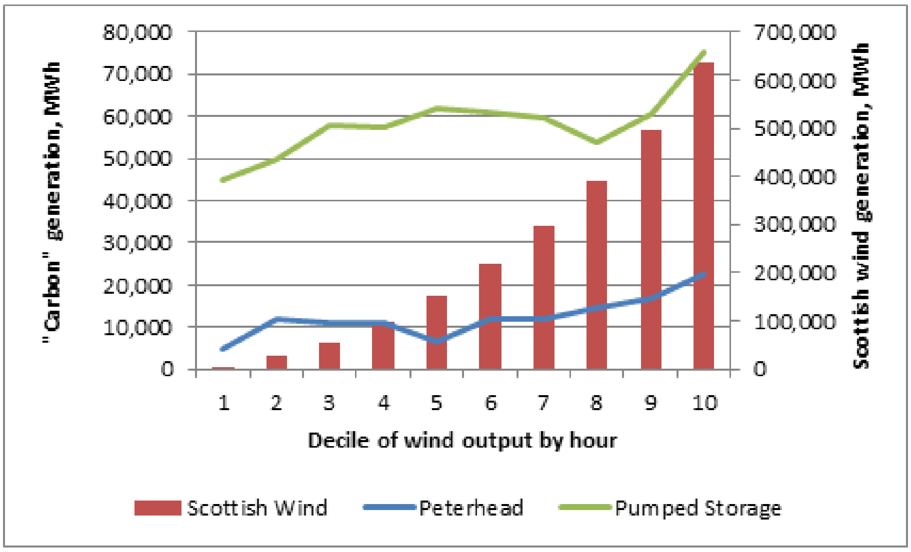


Figure 4: 2015 Analysis

4.16 The proposer highlighted what he believed to be two key flaws in this analysis.

4.16.1 Firstly in principle, a theoretical requirement for the System Operator to constrain on a conventional carbon generator behind a constrained boundary (e.g. for inertia, voltage support, stability) does not represent a marginal cost of transmission network investment. This is because a marginal increase in conventional carbon generation in the affected area does not cause an increase in required transmission network for this purpose and likewise a reduction in conventional carbon in the affected area does not cause a reduction in required transmission network for this purpose. Therefore since this is not an avoidable cost which is either caused by, or avoided by an incremental conventional carbon generator, then it would not be cost reflective to attempt to incorporate this into the locational TNUoS tariff for conventional carbon generators.

4.16.2 Secondly, in practice, the proposer believed that the data used in the analysis has not been interpreted correctly with regard to the following:

- **Constraints are driven by low net demand, not just high gross wind** – The analysis above suggests a correlation between higher wind generation and higher pumped storage generation, but fails to illustrate any correlation with periods of constraint, which would be the more relevant question. By contrast, all this approach is doing is illustrating the effect of winter weather i.e. winter tends to be windier and it also tends to be colder, which tends to cause relatively high wind output and higher dispatch of peaking generators in order to earn relatively high prices in the wholesale power market. However, during such periods when demand is relatively high, sharing continues to take place and conventional carbon generators can generate at the same time as low carbon generators without causing network constraints.

- **Peterhead data set was so limited, that it can not be relied upon for any conclusions** – The only substantial data shown for Peterhead was for the single month of December and even then this did not represent normal market operating characteristics. Therefore it is meaningless to attempt to draw a correlation between Peterhead's single month of operating in December compared with a full 12 months of wind data. The data showed zero generation during the majority of the period analysed namely 8 months March 2015 to October 2015. The data also showed an average load factor for Peterhead of zero between January 2015 and October 2015, rising to 1% in November, then only 13% in December.

4.17 An alternative interpretation of the same data was provided by the proposer as described below (Figure 5). This calculated a net demand profile for Scotland by scaling up the sample wind data to represent the total Scottish wind fleet and also a scaled down set of National Grid published demand data (I014_ND) to represent demand in Scotland. This Scottish net demand was then compared with pumped storage net generation, as well as Scottish nuclear stations as shown in the graph below.

4.18 The proposer noted that they were keen not to re-open the CMP213 debate and keep the scope of the mod narrow.

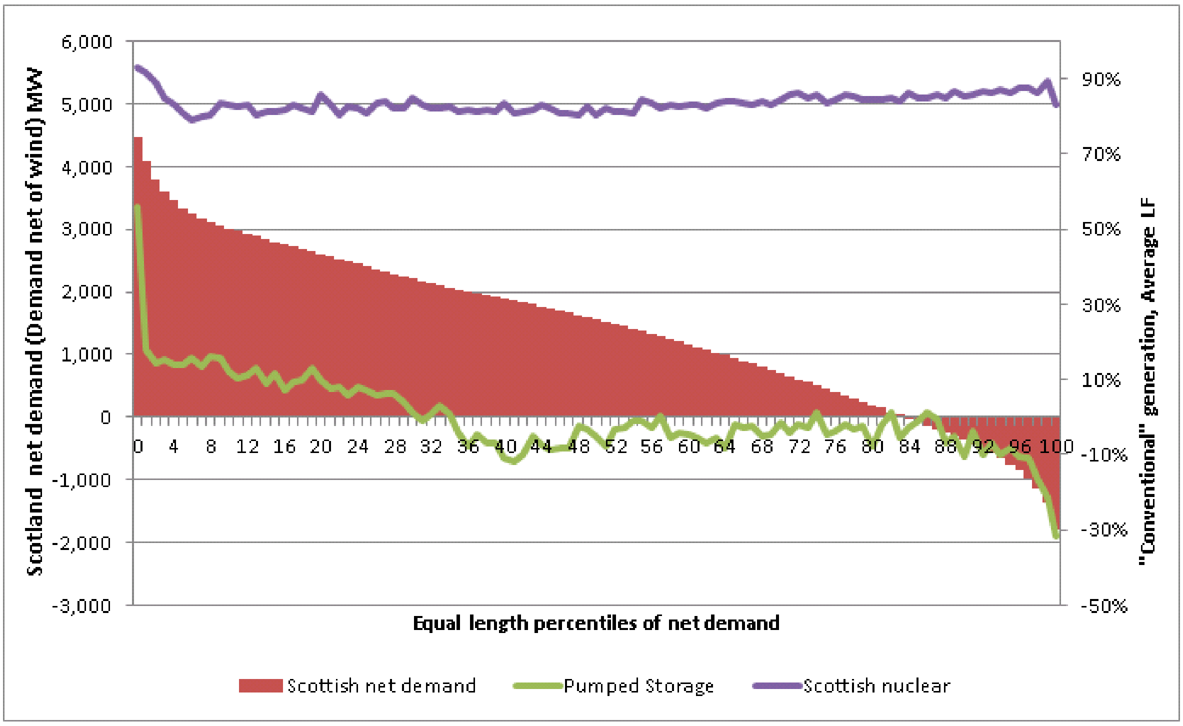


Figure 5: Net Demand Profile for Scotland

4.19 The proposer suggested that the graph in Figure 5 clearly shows several key conclusions including:

4.20 Firstly, pumped storage is tending to relieve constraints, not cause them - The dispatch behaviour of Scottish Pumped Storage is tending to help the transmission network by tending to relieve constraints, so tending to cause a reduction in network cost. This is illustrated by the right hand side of the green curve which shows a net generation load factor becoming increasingly negative (pumping– this, like its generation, entails synchronous operation of pumped storage assets) and reaching circa minus 30% during periods when net demand is lowest (associated with relatively high wind combined with relatively low demand). These are the periods when constraints are most likely to occur and it is clear from the data that during those periods, the pumped storage was tending to pump more and generate less, therefore tending to help the transmission system. This result is consistent with the modification proposal to provide a more full sharing benefit to conventional carbon generation even if they are located in parts of the network which are dominated by low carbon generation.

4.21 Secondly, conventional carbon is sharing with the wind - the left hand side of the graph shows a high degree of sharing during periods when net demand is high (associated relatively low wind and relatively high demand). These are the periods when there is the lowest likelihood of constraints occurring and these are also the periods when the generation from pumped storage has been highest. This result is consistent with the modification proposal to provide a more full sharing benefit to conventional carbon generation even if they are located in parts of the network which are dominated by low carbon generation.

4.22 Thirdly, it appears appropriate to treat two types of conventional generation differently i.e. conventional carbon compared with conventional low carbon - The graph shows a stark difference in the operating characteristics of the Scottish nuclear stations compared with the pumped storage. The nuclear stations only adjust their average load factor within a relatively narrow band and therefore maintain a relatively high load factor irrespective of the level of net demand in Scotland. This demonstrates that in contrast to the pumped storage, the nuclear stations are not sharing with the wind during periods of low net demand when constraints are most likely to occur. Therefore this data supports the position of the proposer that it is appropriate when applying TNUoS tariffs for the tariff formula to make a distinction between the two classes of conventional generation as per the proposal to provide a sharing benefit across all Year-Round circuits for those classed as “Carbon”, but not provide this sharing benefit to those classed as “Low Carbon”.

4.23 A Workgroup member noted the adverse effect of the modification in indicative 2017/18 tariffs on Seabank power station, a CCGT of 800 MW, which based on indicative modelling circulated to the Workgroup by National Grid, could be worse off by a rough indicative estimate of £5.8m p.a. (at least in 2017/18; there is no forecast of the track of CMP268 effects in later years) in terms of extra TNUoS costs it would face if CMP268 were passed. Even allowing for a large error margin on the non-guaranteed indicative effects grid had circulated, it looked as though it can reasonably confidently be said that this asset could face a substantial asset-specific adverse financial effect, whatever the exact number. It is possible, it was suggested, that the asset might close in the fact of extra annual costs of this magnitude, with possible effects on security of supply; the lack of good signs of new-build CCGT is, it was remarked, a live topic in many conversations around energy policy and security of supply in Britain at present.

4.24 An alternative view was provided to point out that even after the adverse financial impact of the proposal for Conventional Carbon in generation charging zone 22 (the zone for Seabank), that zone would still provide one of the lowest generator TNUoS charges of any zone on the GB system. The financial impact of the modification proposal would be to change the locational element of the TNUoS tariff paid by Seabank from being a negative locational charge (receipt of revenue) to a positive locational charge. It is important to note that the monetary impact on Seabank appears relatively large because its small change in tariff is applied to a much larger TEC at 3 to 4 times the TEC of Peterhead and Foyers. After the Generator Residual is applied (forecast by National Grid to be negative in later years), the total TNUoS charge for a low load factor conventional carbon station in zone 22 may be expected to be remain negative from 2018/19 and continue to become increasingly negative over time.

4.25 It was suggested by a Workgroup member thatif parties are concerned that expensive TNUoS charges may potentially provide a price signal for generating stations to close and any impact on security of supply this may have, then it may be more appropriate to consider zones where generators currently face the highest TNUoS charges compared with the rest of the GB system.

4.26 This Workgroup member believed that the proposer's recollection of the origin of the diversity option under CMP213 was not accurate. The diversity option came about because of work which was undertaken to try to prove the relationship between the ALF of power stations in a zone and the constraint costs which arise. This involved modelling scenarios on a simplified model of the network, "ELSI". This modelling showed that sometimes such a relationship existed, but that that this relationship broke down in certain circumstances. This certainly appeared to be the case when there was less diversity in a zone.

4.27 The working group member agreed that the main driver of this was being unable to access bids closer to market price, although this was not the only cause. Issues such as the coincidence of running at times of constraints also had a bearing. The working group member noted that CMP213 Workgroup did not conclude that in such circumstances the higher carbon plant should be treated differently due to driving a lower level of investment, as the proposer asserts as the rationale for CMP268. The only conclusion the CMP213 working group was able to make given the analysis available was that the relationship broke down when there was less diversity, due to a lack of ability to access lower cost bids and that the methodology should reflect this. This is borne out in the CMP213 working group report which says:

"*4.110 The Workgroup found that, where there was insufficient diversity of generation plant types behind a transmission network constraint, the SO would no longer be able to accept bids from a generator close to price of the system marginal plant. In this case the incremental cost of constraints would increase.*"

4.28 The working group member also referred to paragraph 1.15 of Ofgem's decision letter on CMP213. "*1.15. The Year Round tariff would be further adjusted into a 'shared' and 'non-shared' element. The split is based on the proportion of low carbon generation in an area. If the level of low carbon plant behind a boundary is 50% or less, then the entire Year Round tariff is shared. Once this percentage exceeds 50%, an increasing proportion is considered 'non-shared'. This change is to reflect that plant in zones dominated by low carbon plant tend to drive higher levels of constraint costs and therefore investment than if there is a range of plant in a zone.*" The Workgroup member noted that this comment from Ofgem refers to the fact that plant in a zone tends to drive higher levels of constraint costs, but does conclude that it is just lower carbon plant which is doing so.

4.29 The Workgroup member pointed out that the CMP213 solution was also a simplified approach to reflect the effect on the zone as a whole, but clearly a more sophisticated, targeted and complex approach was potentially possible. This was reflected in the CMP213 Workgroup report which said: "*4.137 whilst annual load factor is generation plant specific, the diversity element is related to the zonal availability of sufficient non low carbon plant (or simply – Carbon plant) in a TNUoS zone (i.e. plant with a near marginal bid price). As the Workgroup were minded not to look for a complex solution based on bid price, Method 1 would utilise the ratio of cumulative low carbon (LC) to carbon (C) generation TEC behind a zonal transmission boundary as set out in paragraph 4.130 to establish what proportion of the associated incremental kilometres making up the transmission boundary length were shared or not shared.*"

4.30 The Workgroup member pointed out that this point was recognised by Ofgem too in its decision letter "*2.17. We therefore consider that WACM 2 is an improvement on the existing charging methodology. It represents a simple, transparent proxy for the impact of a generator on constraint costs, and therefore on transmission investment, taking into accounts the mix of generation in an area. However, it will not precisely reflect the impact a generator has on transmission investment in every circumstance, especially at the extremes, for example, when there is 0% or 100% of a particular type of generator in a zone. A more accurate calculation that captured all the factors that affect investment decision-making would require considerably more complexity. We think this would make the charging methodology less transparent and more difficult to forecast. We consider that this would be a barrier to entry, reduce competition and would offset any gains from the additional precision. It will never be possible to exactly capture the impact of an individual generator on the system while remaining within the principles of the ICRP methodology. Balancing accuracy with the simplicity and transparency of tariffs is an important part of the ICRP methodology because of the impact these factors have on competition.*" Therefore, the Workgroup member believed that if the proposer wished to have the specific impact that particular type of higher carbon plant had on the system reflected in the charging methodology, this would require a more sophisticated change than was being proposed under CMP268. That is, new analysis would need to be undertaken and changes would need to be made to the transport model and the tariff model. It would not be sufficient to make a simple change to the tariff model as proposed under CMP268, as this would simply provide a competitive advantage to one or two generators without necessarily improving cost reflectivity of the system.

4.31 Given that the diversity option was focussed on the ability to access lower cost bids, the Workgroup member considered that the current methodology gave the correct signals. The likelihood of being able to access lower cost bids is increased if there is more lower bid cost generation in the zone. The current price signals reflect this by increasing the amount of shared circuits as the amount of diversity increases. This Workgroup member believed that the proposer was incorrect to assert that the current methodology gives a signal for lower cost bid plant to close. Instead it gives a signal for more such plant to locate in the area, as the result of this is to increase the amount of sharing in the price signal. The Workgroup member pointed out that a generator would not make an investment decision based on the current price signal, as the proposer asserts, but on what it believed the signal would be after decision.

4.32 In discussing the investment drivers a Workgroup member noted that the cost of constraints was also driven by the amount of competition behind the constraint to provide low cost bids. The Workgroup member believes that a small amount of higher carbon plant mixed with low carbon plant may not provide a wide enough pool of lower cost plant to provide effective competition. However, it was noted by the Workgroup that the Transmission Constraint Licence Condition is now in force.

2) Distributional Impact

4.33 Some Workgroup members believe that, as it cannot be proven that CMP268 improves the cost reflectivity of the transmission charging methodology, it is simply aimed at providing an unfair competitive advantage to a small subset of participants through redistributing costs between different companies. The analysis that National Grid has undertaken in this respect shows that this advantage would be considerable. The result of this would be that competition in the generation market is distorted. The most significant impact of this would be if this affected the forthcoming Capacity Market auctions in December. Given that the modification was given urgent status on the basis that it should be resolved in time for these auctions, this seems to be a likely outcome.

4.34 Another Workgroup member suggested those generators benefiting from CMP268 may experience a reduction in their TNUoS tariff, but even after this reduction, they are likely to still be paying amongst the highest £/kW TNUoS tariffs of any generator in GB, so it would be misleading to suggest this gave them any form of cost advantage over other generators. The same Workgroup member also suggested that if the reduced £/kW TNUoS tariff following CMP268 is more cost reflective than the baseline, then it implies it represents a correction to a pre-existing market distortion because it means by comparison, it is the baseline which currently causes a discriminatory, non-cost reflective, redistributional economic disadvantage for those affected stations.”Table 1 shows the impact on revenue recovery for 2017/18 if the modification was implemented. As a limited number of Generators will have their Annual Load Factor applied to their Year Round Not Shared (YRNS) Tariff, this results in less revenue (£11.71m) recovered through that particular locational element. To counter act this and maintain overall revenue recovery this then results in the Residual increasing by 0.17 £/kW.

4.35 Table 2 lists those Generators contracted for 2017/18 who will be classed as Conventional Carbon and reside in a Generation zone which has a YRNS tariff (i.e. not 0). These Generators will have their Annual Load Factor applied to their YRNS Tariff. For Generators who currently are forecasted for 2017/18 to have a positive YRNS this results in their forecasted liability reducing. The opposite happens in zones where the YRNS is negative.

4.36 As reducing the negative YRNS tariff increases a Generators liability there could be occasions where the impact on all Generators is a reduction in the Residual.

3) HVDC Impact

4.37 For purely illustrative purposes, further analysis of the impact on 2017/18 tariffs was undertaken to show the effect on Conventional Carbon if the HVDC link was not built. As the HVDC link is classed as a Year Round Shared circuit, this increases tariffs for those zones which utilise the link. Therefore without the HVDC link the overall benefit to Convention Carbon Generators decreases.

4.38 Please note that this analysis was undertaken to show how underlying changes in flows or circuits affecting the locational element of tariffs will affect the impact of this modification on certain Generators, and **not** as a potential scenario for 2017/18 tariffs

Future Years

4.39 Tables 4 to 6 show tariffs from the 5 year forecast undertaken in 2016, which forecasted tariffs out to the 2020/21 year. This shows that YRNS tariffs for Scottish Zones do increase slightly. Therefore if all things stay equal in terms of contracted Generation then this will increase the residual over and above what the residual is currently forecasted

Impact on Revenues 2017/18

	Original	CMP268	Change
Total Infrastructure Revenue (£m)	2735.14	2735.14	
Proportion from Generation (£m)	390.26	390.26	
Proportion from Demand (£m)	2344.88	2344.88	
Local Substation Charge Revenue (Onshore + Offshore) (£m)	241.28	241.28	
Residual Charge for Generation(£/kW)	-2.28	-2.10	
Residual Charge for Demand (£/kW)	47.96	47.96	
Residual Charge Generation broken down			
Proportion from Generation	390.26	390.26	
less revenue from Local tariffs			
Peak	130.15	130.15	
Year Round Shared	20.50	20.50	
Year Round Not Shared	138.03	126.32	-11.71
All Offshore + Onshore Local Substation	241.28	241.28	
Onshore Local Circuit	15.80	15.80	
	545.75	**534.04**	
Revenue to collect through Residual	-155.49	-143.78	11.71
Gen Base	68.31	68.31	
Residual Charge for Generation(£/kW)	-2.28	-2.10	0.17

Table 1: Impacts on Revenue 2017/18

Generation Input Data				NEW	NEW	NEW	NEW		NEW	EXISTING	
Station	Generator Type	Max Contracted TEC at Peak (Transport Model TEC)	ALF	Conventional Carbon	Non Conventional Carbon	Conventional Carbon	Conventional Carbon * ALF	Gen Zone	Year Round Not Shared	Year Round Not Shared	Impact of CMP268 YRNS
BP Grangemouth	CHP	120	61.60%	Yes	0	120	74	9	8.158948485	13.24567811	- 610,407.55
Cruachan	Pump Storage	440	9.23%	Yes	0	440	41	8	1.426292143	15.45023194	- 6,170,533.51
Drax (Biomass)	Biomass	1905	81.80%	Yes	0	1905	1558	15	0.146887797	0.179560209	- 62,240.95
Drax (Coal)	Coal	2001	81.80%	Yes	0	2001	1637	15	0.146887797	0.179560209	- 65,377.50
Fiddlers Ferry	Coal	1455	49.28%	Yes	0	1455	717	15	0.08849286	0.179560209	- 132,502.99
Foyers	Pump Storage	300	15.39%	Yes	0	300	46	1	2.643040442	17.1725935	- 4,358,865.92
Immingham	CHP	1218	54.19%	Yes	0	1218	660	15	0.097301827	0.179560209	- 100,190.71
Lynemouth Power Station	Coal	376	58.02%	Yes	0	376	218	13	2.52827727	4.357254511	- 687,695.44
Peterhead	CCGT	400.00	41.88%	Yes	0	400	168	2	7.19158344	17.1725935	- 3,992,404.03
Saltend	CCGT	1100	79.87%	Yes	0	1100	879	15	0.143422616	0.179560209	- 39,751.35
Seabank	CCGT	1234	26.18%	Yes	0	1234	323	22	-1.60712423	-6.138695111	5,591,958.47
Sellafield	CHP	155	17.34%	Yes	0	155	27	14	0.489572864	2.823518556	- 361,761.58
South Humber Bank	CCGT	1365	32.11%	Yes	0	1365	438	15	0.057650536	0.179560209	- 166,406.70
Wilton	CCGT	141	9.66%	Yes	0	141	14	13	0.420702601	4.357254511	- 555,053.82
											-£11,711,233.58

Table 1: 2017/18 Impacts on Parties Costs

Please note the above table highlights the locational impact of this modification. All Generators will be impacted by this modification as the Residual element of the tariff will increase by **0.17 £/kW. The increase in the Residual will collect an extra £11.7m**

Generation Input Data				NEW	NEW	NEW	NEW		NEW NO HVDC	EXISTING NO HVDC	
Station	Generator Type	Max Contracted TEC at Peak (Transport Model TEC)	ALF	Conventional Carbon	Non Conventional Carbon	Conventional Carbon	Conventional Carbon * ALF	Gen Zone	Year Round Not Shared	Year Round Not Shared	Impact of CMP268 YRNS
BP Grangemouth	CHP	120	61.60%	Yes	0	120	74	9	4.342178	7.049327	- 324,857.84
Cruachan	Pump Storage	440	9.23%	Yes	0	440	41	8	0.746682	8.088389	- 3,230,351.29
Drax (Biomass)	Biomass	1905	81.80%	Yes	0	1905	1558	15	0.001437	0.001756	- 608.81
Drax (Coal)	Coal	2001	81.80%	Yes	0	2001	1637	15	0.001437	0.001756	- 639.49
Fiddlers Ferry	Coal	1455	49.28%	Yes	0	1455	717	15	0.000866	0.001756	- 1,296.07
Foyers	Pump Storage	300	15.39%	Yes	0	300	46	1	1.523510	9.898681	- 2,512,551.36
Immingham	CHP	1218	54.19%	Yes	0	1218	660	15	0.000952	0.001756	- 980.01
Lynemouth Power Station	Coal	376	58.02%	Yes	0	376	218	13	1.487257	2.563151	- 404,536.21
Peterhead	CCGT	400.00	41.88%	Yes	0	400	168	2	4.145395	9.898681	- 2,301,314.23
Saltend	CCGT	1100	79.87%	Yes	0	1100	879	15	0.001403	0.001756	- 388.83
Seabank	CCGT	1234	26.18%	Yes	0	1234	323	22	-1.514004	-5.783007	5,267,948.90
Sellafield	CHP	155	17.34%	Yes	0	155	27	14	0.440849	2.542514	- 325,758.04
South Humber Bank	CCGT	1365	32.11%	Yes	0	1365	438	15	0.000564	0.001756	- 1,627.70
Wilton	CCGT	141	9.66%	Yes	0	141	14	13	0.247478	2.563151	- 326,509.89
											- 4,163,470.86

Table 2: 2017/18 Impact without HVDC

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional 80% Load Factor	Intermittent 40% Load Factor
Zone	**Zone Name**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**
1	North Scotland	0.33	13.48	19.30	-3.38	27.03	21.31
2	East Aberdeenshire	0.66	4.78	19.30	-3.38	20.40	17.83
3	Western Highlands	-0.40	11.85	18.61	-3.38	24.31	19.97
4	Skye and Lochalsh	-4.53	11.85	19.84	-3.38	21.41	21.20
5	Eastern Grampian and Tayside	-0.19	10.22	17.32	-3.38	21.92	18.03
6	Central Grampian	1.63	10.91	18.11	-3.38	25.09	19.10
7	Argyll	0.47	9.00	26.77	-3.38	31.06	26.99
8	The Trossachs	0.82	9.00	15.85	-3.38	20.49	16.07
9	Stirlingshire and Fife	-0.25	5.01	13.29	-3.38	13.66	11.91
10	South West Scotland	1.39	8.15	15.00	-3.38	19.53	14.88
11	Lothian and Borders	2.33	8.15	8.84	-3.38	14.31	8.72
12	Solway and Cheviot	0.95	4.79	8.07	-3.38	9.46	6.60
13	North East England	2.79	3.01	4.24	-3.38	6.05	2.06
14	North Lancashire and The Lakes	1.50	3.01	3.11	-3.38	3.64	0.94
15	South Lancashire, Yorkshire and Humber	3.62	1.18	0.21	-3.38	1.40	-2.70
16	North Midlands and North Wales	3.06	-0.29		-3.38	-0.55	-3.50
17	South Lincolnshire and North Norfolk	0.71	0.63		-3.38	-2.17	-3.13
18	Mid Wales and The Midlands	1.02	-0.11		-3.38	-2.44	-3.42
19	Anglesey and Snowdon	4.05	-0.13	0.00	-3.38	0.57	-3.43
20	Pembrokeshire	9.01	-4.99		-3.38	1.64	-5.38

21	South Wales & Gloucester	6.15	-4.98		-3.38	-1.21	-5.37
22	Cotswold	3.09	1.43	-6.42	-3.38	-5.57	-9.23
23	Central London	-5.26	1.43	-6.80	-3.38	-14.30	-9.61
24	Essex and Kent	-3.57	1.43		-3.38	-5.81	-2.81
25	Oxfordshire, Surrey and Sussex	-1.10	-3.44		-3.38	-7.23	-4.76
26	Somerset and Wessex	-1.22	-4.86		-3.38	-8.49	-5.33
27	West Devon and Cornwall	0.22	-6.28		-3.38	-8.19	-5.89

Table 4: 2016 5 Year Forecast 2018

Generation Tariffs		**System Peak Tariff**	**Shared Year Round Tariff**	**Not Shared Year Round Tariff**	**Residual Tariff**	**Conventional 80% Load Factor**	**Intermittent 40% Load Factor**
Zone	**Zone Name**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**
1	North Scotland	2.38	11.09	22.30	-5.37	28.17	21.36
2	East Aberdeenshire	2.78	3.93	22.30	-5.37	22.85	18.50
3	Western Highlands	2.06	10.23	21.53	-5.37	26.41	20.25
4	Skye and Lochalsh	-2.19	10.23	22.77	-5.37	23.40	21.50
5	Eastern Grampian and Tayside	4.03	9.99	21.23	-5.37	27.88	19.85
6	Central Grampian	3.58	9.03	19.61	-5.37	25.04	17.86
7	Argyll	2.60	7.66	28.01	-5.37	31.36	25.70
8	The Trossachs	2.82	7.66	17.26	-5.37	20.84	14.96
9	Stirlingshire and Fife	1.85	7.10	16.72	-5.37	18.89	14.19
10	South West Scotland	2.42	6.69	16.20	-5.37	18.60	13.51
11	Lothian and Borders	3.46	6.69	10.46	-5.37	13.90	7.77
12	Solway and Cheviot	1.71	3.99	9.13	-5.37	8.66	5.35
13	North East England	3.37	2.38	4.72	-5.37	4.63	0.30
14	North Lancashire and The Lakes	1.76	2.38	3.37	-5.37	1.66	-1.05

15	South Lancashire, Yorkshire and Humber	4.14	0.63	0.26	-5.37	-0.48	-4.86
16	North Midlands and North Wales	3.21	-0.45		-5.37	-2.51	-5.55
17	South Lincolnshire and North Norfolk	1.74	-0.10		-5.37	-3.71	-5.41
18	Mid Wales and The Midlands	0.93	0.19		-5.37	-4.29	-5.29
19	Anglesey and Snowdon	3.95	0.02	0.00	-5.37	-1.41	-5.36
20	Pembrokeshire	8.58	-5.39		-5.37	-1.10	-7.53
21	South Wales & Gloucester	5.53	-5.46		-5.37	-4.20	-7.55
22	Cotswold	2.34	1.97	-7.52	-5.37	-8.97	-12.10
23	Central London	-5.47	1.97	-7.18	-5.37	-16.45	-11.77
24	Essex and Kent	-3.73	1.97		-5.37	-7.53	-4.58
25	Oxfordshire, Surrey and Sussex	-1.12	-3.09		-5.37	-8.96	-6.61
26	Somerset and Wessex	-2.01	-5.53		-5.37	-11.80	-7.58
27	West Devon and Cornwall	-2.08	-8.41		-5.37	-14.18	-8.73

Table 5: 5 Year Forecast 2019/20.

Generation Tariffs		System Peak Tariff	Shared Year Round Tariff	Not Shared Year Round Tariff	Residual Tariff	Conventional 80% Load Factor	Intermittent 40% Load Factor
Zone	**Zone Name**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**	**(£/kW)**
1	North Scotland	2.58	11.82	22.83	-9.69	25.18	17.87
2	East Aberdeenshire	3.04	4.46	22.83	-9.69	19.75	14.92
3	Western Highlands	2.22	12.43	23.38	-9.69	25.86	18.66

4	Skye and Lochalsh	2.22	12.43	26.22	-9.69	28.70	21.50
5	Eastern Grampian and Tayside	4.21	11.06	21.48	-9.69	24.85	16.21
6	Central Grampian	3.54	10.03	19.65	-9.69	21.52	13.96
7	Argyll	2.61	8.58	27.69	-9.69	27.47	21.43
8	The Trossachs	2.70	8.58	17.01	-9.69	16.89	10.75
9	Stirlingshire and Fife	2.12	8.25	16.67	-9.69	15.70	10.28
10	South West Scotland	2.54	7.66	15.89	-9.69	14.87	9.27
11	Lothian and Borders	3.65	7.66	10.25	-9.69	10.34	3.62
12	Solway and Cheviot	1.75	5.01	8.52	-9.69	4.58	0.83
13	North East England	3.74	3.96	5.53	-9.69	2.75	-2.58
14	North Lancashire and The Lakes	1.77	3.96	2.00	-9.69	-2.75	-6.11
15	South Lancashire, Yorkshire and Humber	4.15	0.52	0.22	-9.69	-4.90	-9.27
16	North Midlands and North Wales	3.18	-0.44		-9.69	-6.87	-9.87
17	South Lincolnshire and North Norfolk	1.66	-0.15		-9.69	-8.16	-9.75
18	Mid Wales and The Midlands	0.83	0.47		-9.69	-8.49	-9.51
19	Anglesey and Snowdon	2.71	1.32		-9.69	-5.93	-9.17
20	Pembrokeshire	8.65	-5.50		-9.69	-5.45	-11.89
21	South Wales & Gloucester	5.69	-5.69		-9.69	-8.55	-11.97
22	Cotswold	2.28	2.09	-7.83	-9.69	-13.57	-16.69
23	Central London	-5.65	2.09	-7.62	-9.69	-21.30	-16.48
24	Essex and Kent	-3.75	2.09		-9.69	-11.77	-8.86
25	Oxfordshire, Surrey and Sussex	-1.26	-3.06		-9.69	-13.40	-10.92
26	Somerset and Wessex	-1.86	-3.62		-9.69	-14.45	-11.14
27	West Devon and Cornwall	-2.04	-7.89		-9.69	-18.04	-12.85

Table 6: 2016 5 Year Forecast 2020/21.

4) Impact on Customer (indirect impact and regional security of supply impact)

4.40 This section details the impact on the customer as identified by the Workgroup.

4.41 The Workgroup discussed the impact this proposal will have on customers, both direct and indirect and also the impact this will have on regional security of supply.

4.42 The Workgroup agreed that this impacts on generation residual where there is a decrease in the negative residual this will increase costs for all generators. The modification could result in certain circumstances increase the costs for generators due to adjustments in the residual. These effects may have a marginal impact on regional security of supply. This is a re-apportion of costs for generators.

4.43 The Workgroup concluded that this modification would have no impact on the demand residual.

4.44 In one Workgroup members view it was noted that if this defect is not corrected, then it would result in at least three key types of harm to regional peak security:

4.45 Firstly, competition is distorted by a non-cost reflective economic disadvantage for Conventional Carbon generators which are located in zones with a high proportion of low Carbon generation.

4.46 Secondly, the defect will cause higher cost to customers than would otherwise be the case. This is because generators will face the incentive to make investment, or closure decisions which do not reflect the economic impact on the investment cost of the transmission network which they cause. This would result in an outcome which is less economically efficient at a higher cost to society and ultimately a higher cost to customers.

4.47 Thirdly, there is a locational security of supply risk. The current defect provides the perverse economic price signal that as more intermittent low carbon plant is built in a zone, then low load factor peaking plant experience higher TNUoS charges. This is a self-reinforcing “death spiral” for low load factor peaking plant because as the charges increase and low load factor peaking plant are encouraged to close, then this would further reduce the assumed degree of sharing, which would feed back to further increase the price signal for remaining low load factor peaking plant to close. If left uncorrected, then for that zone, the “death spiral” would result in a shortage of low load factor peaking plant and an increasing reliance on imported power to meet peak demand, which would result in an increasing risk to security of supply for customers in that zone.

4.48 Another Workgroup member noted that the above comments were predicated on the modification providing a more cost reflective signal. This Workgroup member believed that the price signals were indeed appropriate as they encouraged more diversity into an area which would increase the amount of sharing. This Workgroup member noted that the modification would certainly provide some plant with a considerable cost advantage over others. It was not clear whether the modification would prevent plant from closing inappropriately however without further analysis. The Workgroup members noted that it could similarly be argued that if the CMP268 signals were not cost reflective, then this could indeed result in inappropriate plant closures. Another Workgroup member suggested those generators benefiting from CMP268 may experience a reduction in their TNUoS tariff, but even after this reduction, they are likely to still be paying amongst the highest £/kW TNUoS tariffs of any generator in GB, so it would be misleading to suggest this gave them any form of cost advantage over other generators. A Workgroup member also suggested that if the reduced £/kW TNUoS tariff following CMP268 is more cost reflective than the baseline, then it implies it represents a correction to a pre-existing market distortion in the form of a non-cost reflective, redistributionary economic disadvantage for those affected stations under the baseline.

Further Workgroup discussions following Workgroup Consultation

4.49 The Workgroup noted that there had been five responses to the Workgroup Consultation. It was noted that the responses were from Workgroup members other than that from Drax Power. In addition the responses largely covered what the group had covered within their initial discussions. SSE submitted additional analysis as part of their consultation response. It was suggested that this should be discussed as in depth as possible within the timescales that the Workgroup are working under due to the urgency of the modification. Ofgem stated that there was a clear conflict between working on analysis and the process timescales but that they would like to talk through the new analysis that had been provided. The Ofgem representative noted that this analysis had been provided at Workgroup Consultation stage and as a result the Industry would not have the opportunity to comment on the discussions below.

New analysis evidence supporting CMP268 (also in Annex 7)

4.50 John Tindal talked the group through his new analysis, outlined below.

Resulting Year Round tariff comparison of SQSS, CMP268 and Baseline

4.51 SSE carried out analysis comparing the Year Round TNUoS charges by generation charging zone which would result from the implementation of CMP268. These charges were compared with the charges using the Baseline methodology and the charges which would result from multiplying the Year Round charges by the SQSS scaling factors[10] for a range of different types of generator including Peaking, CCGT, nuclear and wind. This used the tariffs from National Grid published June 2016 Quarterly Update 2017-18[11].

4.52 The proposer stated that the analysis in the graphs below highlighted that CMP268 will tend to result in Year Round TNUoS charges which are more cost reflective for Conventional Carbon plant with operating characteristics which result in an ALF anywhere between 0% and 100%. He explained that this is because the analysis demonstrates that CMP268 is more cost reflective of the SQSS for a zero (or very low) ALF generator, while it is as cost reflective as the Baseline for Conventional Carbon generators with a very high ALF and CMP268 also tends to be more cost reflective than Baseline in the method it calculates charges for Conventional Carbon generators which have an ALF anywhere in the range of 0% and 100%.

4.53 The proposer suggested to understand why CMP268 is more cost reflective across a range of Conventional Carbon generators with different ALFs, it is helpful to understand the

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[10] NETS Security and Quality of Supply Standard Issue 2.2 - 5 March 2012 - Current http://www2.nationalgrid.com/uk/industry-information/electricity-codes/sqss/the-sqss/

[11] http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

interaction between the SQSS and a full-blown Cost Benefit Analysis. The SQSS scaling factors are best considered as a form of "average" approximation which is cost reflective of a full blown Cost Benefit Analysis. It is therefore reasonable to conclude that in reality generators with operational characteristics which may be different from the SQSS "average" (higher, or lower) may be expected to cause a different (higher, or lower) cost within a CBA analysis and it is therefore reasonable that this difference from SQSS "average" be taken account of in the charging methodology. The proposer referred to analysis that his company had commissioned during CMP213 which described this relationship as follows:

4.54 "The aim of a cost-reflective charging methodology must be to apply charges that reflect the **actual costs incurred** in accommodating additional generation capacity. However, it is important to note that the pseudo-cost benefit approach (CBA) dual background methodology [of the SQSS] is no more than a deterministic short-hand for the full-blown CBA used to justify individual transmission investment decisions**. It [SQSS] is best considered as representing the "average" outcome of a range of full CBA studies**" [12] [emphasis added]

4.55 A Workgroup member agreed that the economic criterion in the SQSS is not meant to be fully cost reflective and is in fact an approximation of a full cost benefit analysis. Some Workgroup members were also concerned that this analysis had been provided to the group at the last moment and has not afforded them the time to discuss is having analysed fully what it was that the SQSS actually said. A Workgroup member suggested that it would be beneficial and essential to look at the relevant aspect of the SQSS. The Workgroup considered the SQSS and the scaling factors. It was noted that **Appendix E** defined these as follows:

"Directly Scaled Plant
E.3 In the Economy planned transfer condition the registered capacities of certain classes of power station are scaled by fixed factors, known as DT, for classes T of power station. These factors are set as follows:

> *E.3.1 For nuclear stations, and for coal-fired and gas-fired stations fitted with Carbon Capture and Storage, DT = 0.85*
>
> *E.3.2 For stations powered by wind, wave, or tides, DT = 0.70.*
>
> *E.3.3 For pumped storage based stations, DT = 0.5*
>
> *E.3.4 For interconnectors to external systems regarded as importing into GB at the time of peak demand, DT = 1.0*
>
> *E.4 The NETS SO will review the appropriateness of these factors and revise*

[12] Review for SSE of Poyry's Report to Centrica Energy "Review of Ofgem's Impact Assessment on CMP213, P E Baker, March 2014. https://www.ofgem.gov.uk/sites/default/files/docs/2014/04/review_for_sse_of_poyrys_report_to_centrica_energy_titled_review_of_ofgems_impact_assessment_on_cmp213_0.pdf

them where necessary, based on alignment with cost benefit analysis. The period between reviews shall be no more than five years, but may be less if required

Variably Scaled Plant

E.5 All remaining directly connected power stations and embedded large power stations on the system at the time of the ACS peak demand are considered contributory and their output is calculated by applying a scaling factor to their registered capacity such that their aggregate output is equal to the forecast ACS peak demand minus the total output of directly scaled plant."

4.56 The Workgroup member went onto explain that the SQSS scaling factors contribute as an investment driver and are not intended to be used as a substitute for the ALF for charging purposes. Another Workgroup member raised a concern that this SSE analysis seemed to suggest that the Year Round charge multiplied by the SQSS scaling factors was the "right answer" and stated that this wasn't the conclusion of the CMP213 working group. In addition it was noted that this analysis did not show conclusions for individual stations. It was suggested that the class of plant in the 'background' should be used. It was noted background scaling factors and categories used were what drive investment, in addition it was questioned how the TUNoS tariffs are linked to the SQSS.

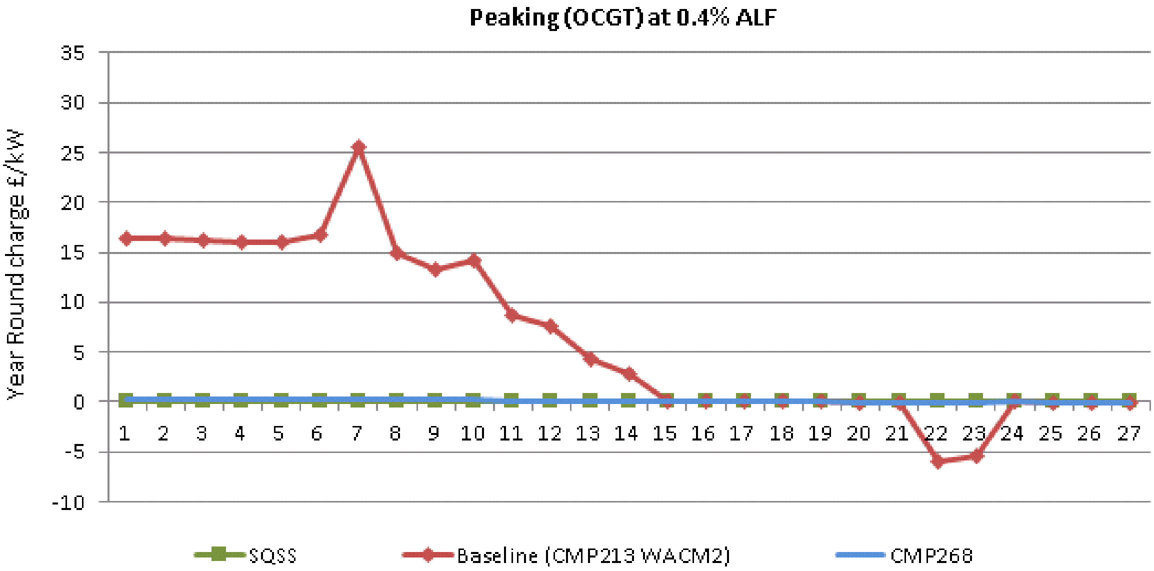
4.57 The proposer moved onto explain the next part of the analysis below:

More cost reflective for Peaking (OCGT) generators

He noted that the improved cost reflectivity of CMP268 is most apparent when considering the case of a peaking plant such as an OCGT. The graph below illustrates that the Year Round TNUoS charge for an OCGT arising from CMP268 would be almost identical to that derived from multiplying the Year Round charge by the SQSS scaling factor. He stated that this is because for an OCGT, the SQSS uses a scaling factor of zero, while for a station with an ALF of zero (or very close to zero), then CMP268 would result in an identical, or almost identical Year Round charge. In addition he believed that by contrast, the Year Round TNUoS charge for this class of generator resulting from the Baseline is much less cost reflective because it its application of 100% to the Not Shared Year Round tariff element results in charge which is much higher than that derived using the SQSS factors in Northern zones and much lower than SQSS in zones 22 and 23 which exhibit a substantial negative Not Shared Year Round tariff.

4.58 The proposer stated that the rational for the zero scaling factor for OCGTs within the SQSS is that this type of generator will tend to have a negligible contribution to constraint cost, therefore a negligible contribution to the cost of network investment associated with the

Economy Criterion of the SQSS.



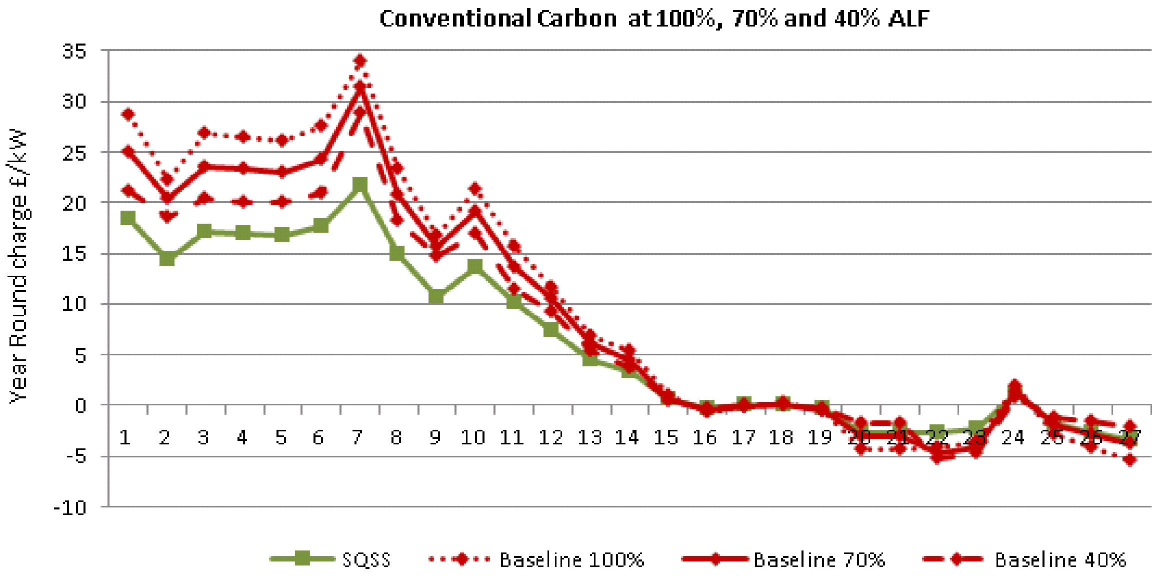
4.59 A Workgroup member stated that the SQSS factor does not drive the charge that the generator would pay, it was the ALF, and as such the analysis was not comparing similar things. He went onto question the relevance of the graph provided and said that all it really showed was that a Year Round charge scaled by 0.4 was very close to one scaled by 0; not that either were actually the correct answer. The proposer stated that the charge that the OCGT should receive should be reflective of the SQSS and the fact that it doesn't cause cost in the Economy Criteria.

4.60 An additional point that was raised by another Workgroup member was that the proposer seemed to be questioning the scaling used for conventional carbon generators in CMP213 compared with those used under the SQSS, but why wasn't the modification targeting the all scaling percentages? The Workgroup member suggested that the Workgroup should be looking at all rather than one category in isolation. How could it not be cost reflective for OCGTs but be working perfectly for all other categories? In addition, he also suggested that the group could have looked further into the load factors in relation to the way that charges are derived but there has not been opportunity to do so due to the time constraints on the modification.

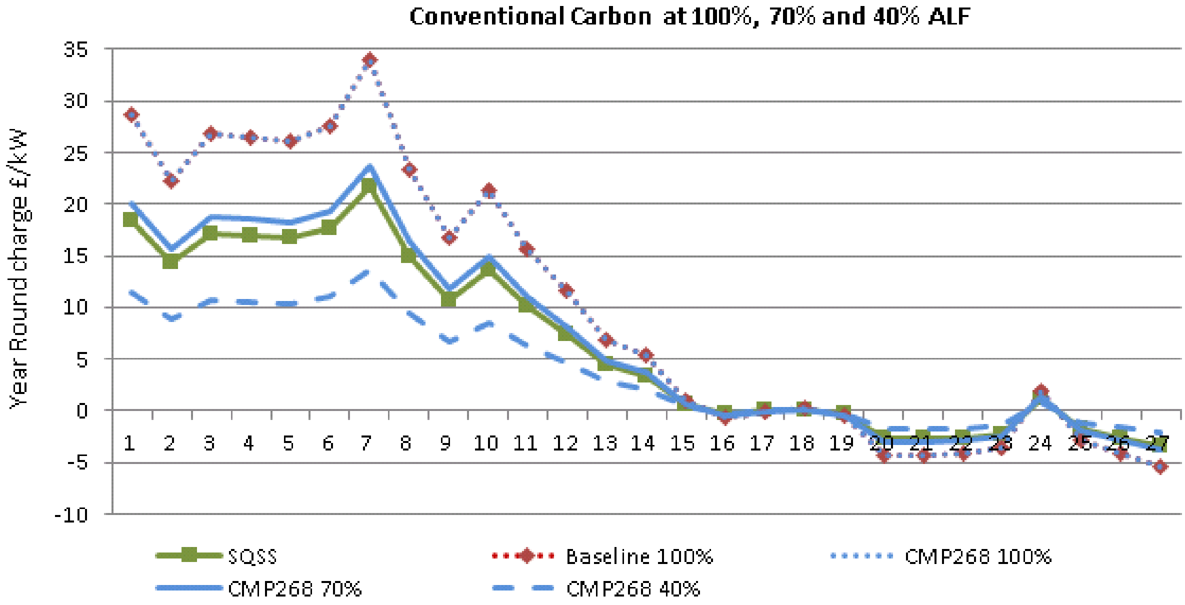
4.61 The Workgroup debated the use of ALFs within charging. It was suggested by some Workgroup members that the proposer's analysis implies that the defect lies in the fact that the ALFs differ from the SQSS factors. An example of this is when wind has an SQSS scaling factor of seventy percent, but wind farms do not have ALFs anywhere near as high. It was noted that ALF is actually used as it is deemed to be more cost reflective. The proposer stated that the ALF was not the issue for either OCGTs, or wind and went on to illustrate that Baseline approach for wind (which is not altered by CMP268) of applying 100% to the Not Shared Year Round element plus the ALF on the Shared Year Round element results in a set of charges for wind which are very close to those suggested by using the 70% scaling factor for wind used by the SQSS.

More cost reflective for CCGT generators

4.62 The proposer stated that the graph below illustrates that for a Conventional Carbon generator such as a CCGT, with an ALF ranging between 40%, 70% and 100%, the charges derived from the Baseline methodology would all be higher in Northern zones than those calculated by scaling the Year Round tariffs by the SQSS scaling factors. He believed that this showed that the Baseline methodology is over charging Conventional Carbon generators in these zones.



4.63 He also explained that the graph below shows a similar set of tariffs derived from the CMP268 methodology from which he believed three key conclusions can be drawn. Firstly, he stated that it shows that for a notional 100% ALF generator, CMP268 would provide a set of Year Round charges that are identical to the Baseline, therefore for a notional 100% ALF generator, CMP268 is equally cost reflective compared with Baseline. Secondly, the graph illustrates that for a Conventional Carbon generator with an ALF of 70%, CMP268 would result in a set of tariffs which are very close to those which would arise from multiplying the Year Round tariffs by the SQSS scaling factors. Thirdly, for CCGTs with a relatively low ALF, the CMP268 methodology would provide a set of charges which tend to converge towards those which would arise from using the SQSS scaling factors for a Peaking plant (0% scaling), which is consistent with low ALF CCGTs exhibiting operating characteristics which are in practice closer to those of a peaking OCGT. He went onto explain that this result is consistent with expectation because the SQSS scaling factor by definition represents a form of average, so there will always tend to be some individual stations which tend to cause a network investment cost higher than that indicated by the SQSS and others which tend to cause a cost of investment lower than that indicated by the SQSS.



Conventional Carbon at 100%, 70% and 40% ALF
Year Round charge £/kW
35
30
25
20
15
10
5
0
-5
-10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27
SQSS
Baseline 100%
CMP268 100%
CMP268 70%
CMP268 40%

4.64 A Workgroup member restated that the ALF is not the proxy for the SQSS scaling factor. It was suggested that the graphs did not show the group anything tangible as the scaling factor is not the basis for setting the tariffs. The Workgroup member also questioned where 'sharing' was described within the SQSS. The Workgroup member went onto explain that this analysis was not relevant as it simply showed the difference between the SQSS and the ALFs.

4.65 Another Workgroup member explained that the SQSS assesses whether new investment is required by applying scaling factors to plant to assess on a number of different factors and whether you need to build under peak or non-peak conditions; what assets are there; how restricted the network may be and noted that the assessment does not look at load factor.

4.66 It was suggested that the proposer's analysis suggests that he believed that using the ALF in the calculations is not correct. This Workgroup member stated that they would be supportive of a modification that looked into this and that OCGTs should not pay year round tariffs, as suggested by the SQSS as they do not contribute to year round investment. The proposer stated that the ALF is fine for all generator types and that the calculation of Diversity including the application of the Not Shared Year Round element works well for wind and nuclear.

4.67 It was stated that the load factor when plotted against the SQSS does not work and breaks down as the loads factors are different to the scale factor. It was suggested, in addition, that the first graph shows that the baseline, as it stands today works as it should.

4.68 The proposer stated that the cause of the breakdown is low carbon plant and that by contrast, Carbon plant does not cause sharing to break down because they will tend to avoid generating during periods of constraint since these periods will tend to be associated with periods of relatively low wholesale power prices, while even if they are generating, then they can be bid-off by the System Operator at a relatively low cost. He went on to explain that at the time of CMP213, the solution proposed in CMP268 was not an option presented to Ofgem for consideration. A Workgroup member added that wider drivers of investment costs such as scaling factors and bid prices were also not provided as options for Ofgem to consider under CMP213 as the Workgroup considered that the diversity methodology was the most appropriate solution on balance.

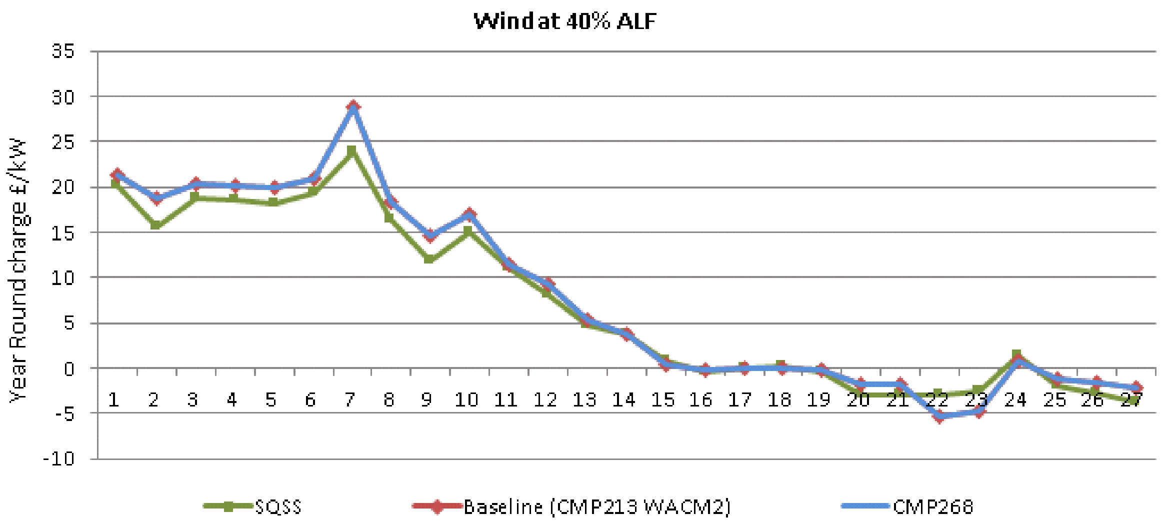
4.69 This Workgroup member noted that a lack of diversity was stated as the reasons why the relationship between ALF and constraint costs broke down and why the network would then be built to meet close to the total capacity of plant behind a boundary, both carbon and low carbon. The Workgroup member stated that the issue is about accessing bid prices and if there is a low amount of carbon plant within a zone you cannot access lower cost prices. The proposer noted that if you are not 'running' then you will not be causing a constraint on the system. In addition it was suggested by a Workgroup member that the initial reason for ALF being introduced what that it provided a discount to Scotland. This Workgroup member went onto state that the analysis provided does suggest that there maybe some additional defects that could be addressed in the future but that this modification only pin points one category of plant and that this was the failure in the defect, in their view. A wider review of the decisions under CMP213 would be required, not just addressing one area without the consideration of all categories of plant and the wider picture. The proposer reiterated that they believed it is appropriate to deal individually with the specific defect that they have identified in this modification proposal and that it is not necessary to consider other wider issues at the same time.

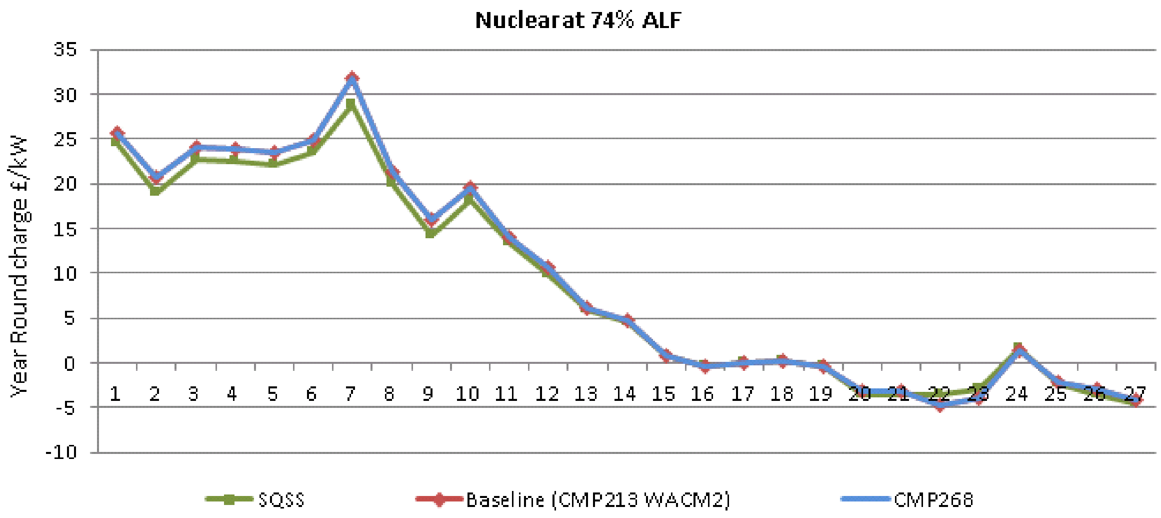
4.70 The proposer stated that conventional carbon does not cause a constraint cost as it's a low cost to come off of the system and as a result are not breaking down sharing. It was suggested by another Workgroup member that this would be a lower cost than low carbon plant, not necessarily low or zero. The Proposer explained that this is why the ALF is used, as the higher ALF stations pay higher TNUoS charges to reflect their impact on higher constraint costs and that OCGTs have a much smaller impact on constraint costs. It was also noted that the CUSC does not seek to apportion the exact impact a specific station has on the system at a point in time as it has averaging principles to ensure that there are not barriers to entry within the market.

Equally cost reflective for Low Carbon generators (Wind and Nuclear)

4.71 The proposer stated that the two graphs below illustrate that CMP268 would provide Year Round charges which are identical to those provided by the Baseline charging methodology for Low Carbon generators (wind and nuclear), both of which appear to be closely cost reflective of the SQSS.

4.72 He went onto explain that this is illustrated by a 40% ALF wind farm in charging zone 1 paying 40% of the Shared Year Round tariff and 100% of the Not-shared Year Round tariff, which for zone 1 provides a weighted average charge of £ 21.22 per kW (0.4x£12.46 plus 1x£16.24 = £21.22). This charge equates to 74% of the combined Year Round tariff (£21.22 divided by £28.7), which is very close to the SQSS scaling factor of 70% for wind farms.





In addition he explained that the table below shows the scaling factors used for the SQSS comparison:

	SQSS
Wind	70%
Conventional	64%
Nuclear	85%
Peaking	0%

4.73 A Workgroup member restated the view that this analysis did not illustrate anything as it was based on the false premise that the SQSS scaling factors should be a proxy for the correct level of ALF.

4.74 A Workgroup member questioned the use of a 40 percent load factor for illustrating the differences in wind charges. This seemed high for onshore wind, but perhaps not for offshore stations. The proposer pointed out that the 40% ALF example results in charges for Scottish wind in excess of the SQSS scaling factor and a potential alternative example using a lower ALF may result in illustrative charges for wind which are even closer to those suggested by the SQSS scaling factor.

Empirical evidence that Conventional Carbon generators do tend to operate in a way which is consistent with CMP268

4.74 The proposer stated that SSE carried out analysis comparing MWh volumes for FPNs, Bids and Offers for Conventional Carbon generators (CCGT and Pumped Hydro) in Scotland compared with net demand in the three financial years of 2013/14, 2014/15 and 2015/16. He stated that this analysis suggested that the historic operational characteristics of Conventional Carbon generators has been consistent with the principles of sharing used in both the Baseline and CMP268.

4.75 He noted that Scottish net demand was calculated as Scottish demand minus Scottish wind generation. This used National Grid published INDO demand, adding back in embedded wind, then applying a 9% pro-rata adjustment[13] to derive an equivalent figure for Scottish demand. Scottish wind was calculated from all transmission connected wind farms in Scotland, with a pro-rata increase to match the total installed capacity of wind in Scotland.

Scottish net demand is closely correlated with constraint cost

4.76 In addition the proposer stated that the graphs below show net demand (INDO - Scottish wind) sorted into percentiles plotted against accepted bid volumes (MW) from wind. This demonstrates that the level of Scottish "net demand" is a good measure of the likelhood that a particular half hour period may include expensive constraint payments to curtail wind generation in Scotland. This is because the periods of high bid volumes of Scottish wind are associated with periods of low net demand in Scotland and importantly, economic merit order suggests that dispatchable peaking generators are less likely to be running during those low net demand periods.

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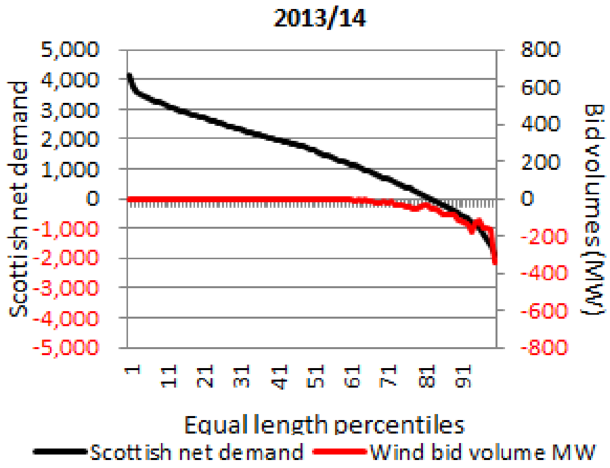
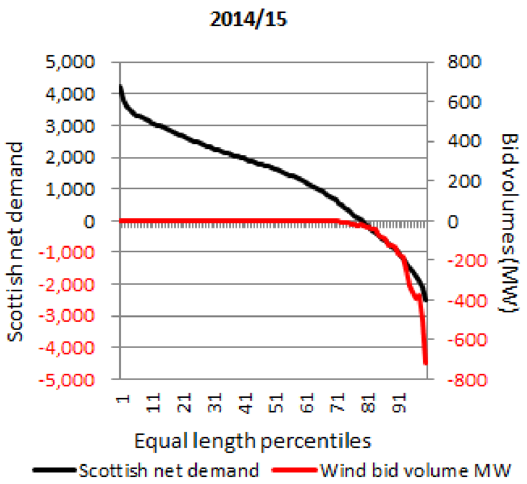
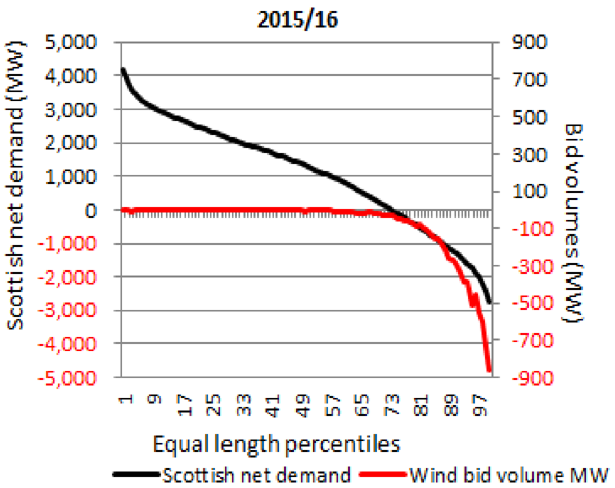
[13] Based on Ofgem published Renewables Obligation eligible demand for Scotland as a % of GB eligible demand https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-total-obligation-201516

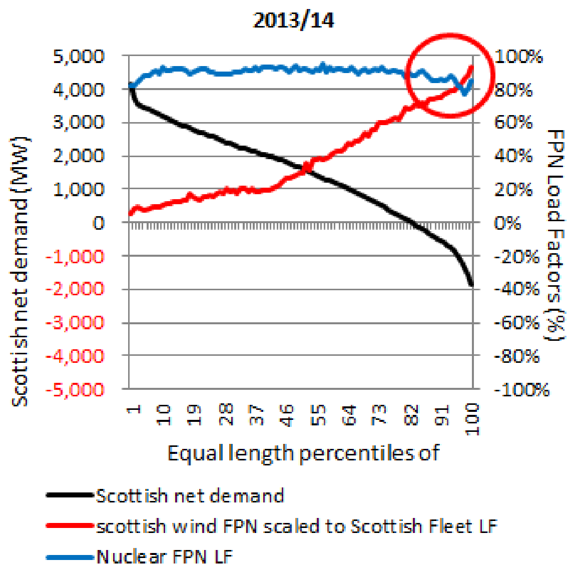

2013/14
Scottish net demand
Bid volumes (MW)
Equal length percentiles
Scottish net demand
Wind bid volume MW

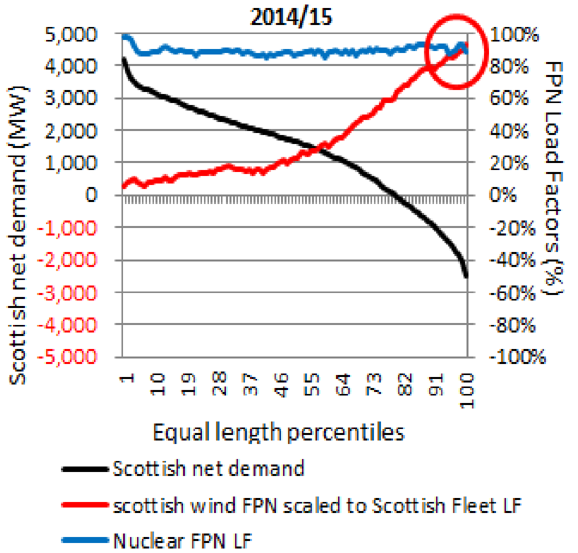

2014/15
Scottish net demand
Bid volumes (MW)
Equal length percentiles
Scottish net demand
Wind bid volume MW

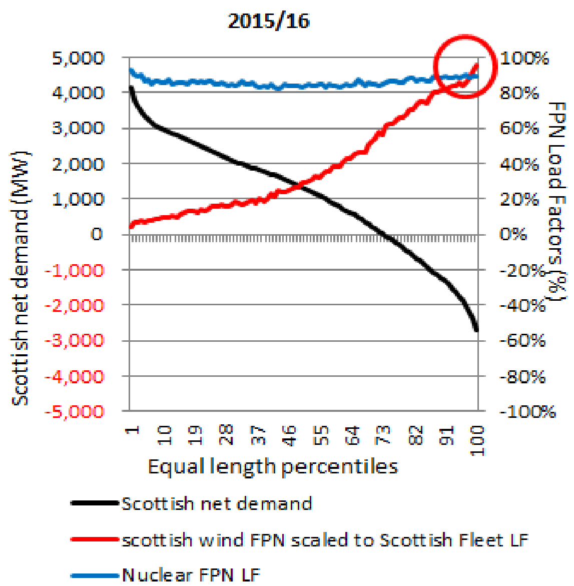

2015/16
Scottish net demand (MW)
Bid volumes (MW)
Equal length percentiles
Scottish net demand
Wind bid volume MW

Low Carbon generation correlated with periods of constraint

4.77 The proposer noted that the graphs below illustrate the same periods of net demand (INDO - Scottish wind) sorted into percentiles, but this time plotted against the FPN Load factors (%) of Scottish Low Carbon generation (nuclear and wind). This illustrates that these classes of Low Carbon generators have historically exhibited relatively high load factors close to 100% during periods of relatively high constraints volume. He stated that this relatively high correlation with periods of constraints combined with the relatively expensive bid prices means that when Low Carbon generators have limited capacity of Carbon generation to share with, then Low Carbon generators may tend to cause a network investment cost which is close to their full capacity. In addition that this result is broadly consistent with the continued application of 100% of the Not Shared Year Round tariff element for Low Carbon generators which is used by the Baseline and which remains unchanged following the implementation of CMP268.



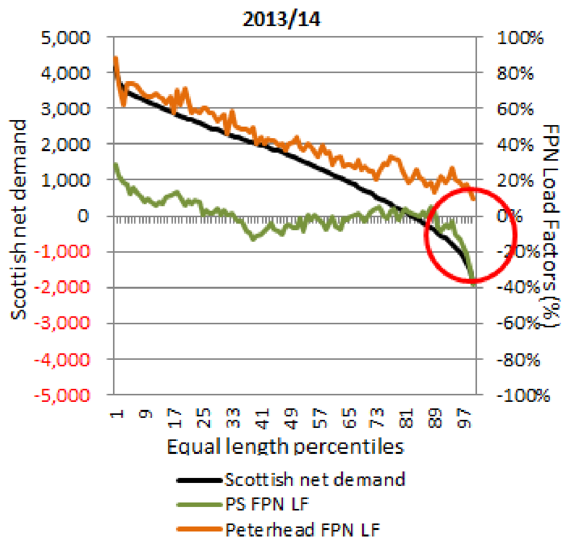


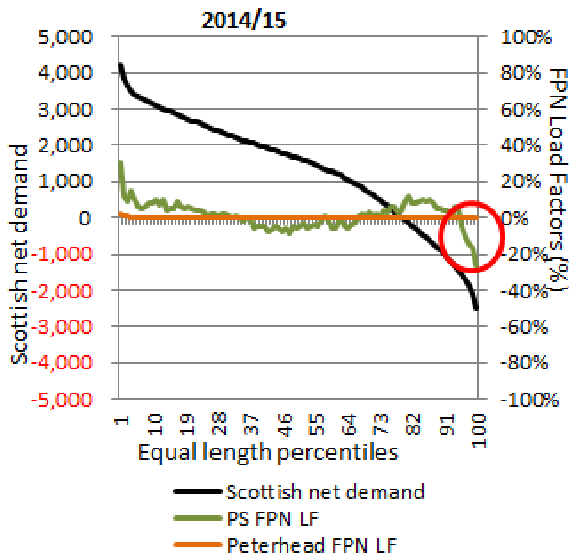


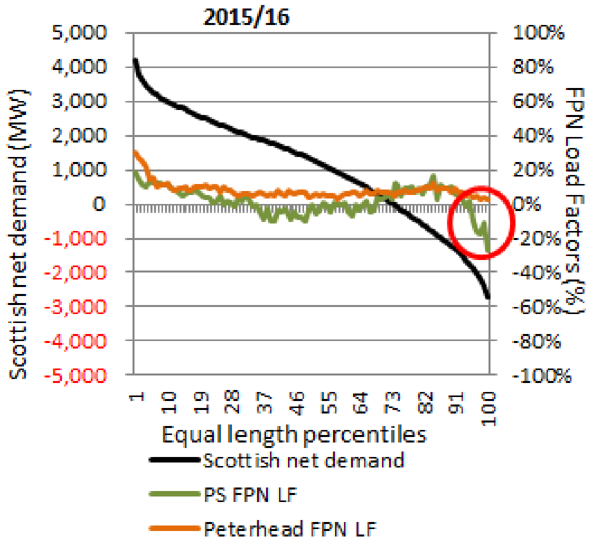
Marginal Conventional Carbon generation is inversely correlated with periods of constraint

4.78 The proposer stated that the graphs below are the same format as those above, except this time plotted against the FPNs of Scottish Conventional Carbon generators. He stated that these graphs illustrate that these Conventional Carbon generators (Peterhead and Pumped Hydro storage) are inversely correlated with periods of constraint. This means that during periods when constraints are most likely, then the load factor of these stations is relatively close to zero, so the cost of constraints to which they are contributing is relatively small compared with their installed capacity. This inverse correlation combined with their relatively inexpensive bid prices means that they will tend to cause relatively limited network investment cost for the purpose of managing constraints, even if the boundary they are behind is dominated by Low Carbon generation. This result is contrary to the Baseline methodology which charges these stations 100% of the Not Shared Year Round tariff and this result is key to the defect which the CMP268 proposal is designed to correct.

4.79 The proposer stated that Peterhead was not operating commercially in the wholesale market during 2014/15, or 2015/16, so the data shows its FPNs being at, or close to zero in those years. The non zero FPNs of Peterhead represent generation during a small number of weeks.







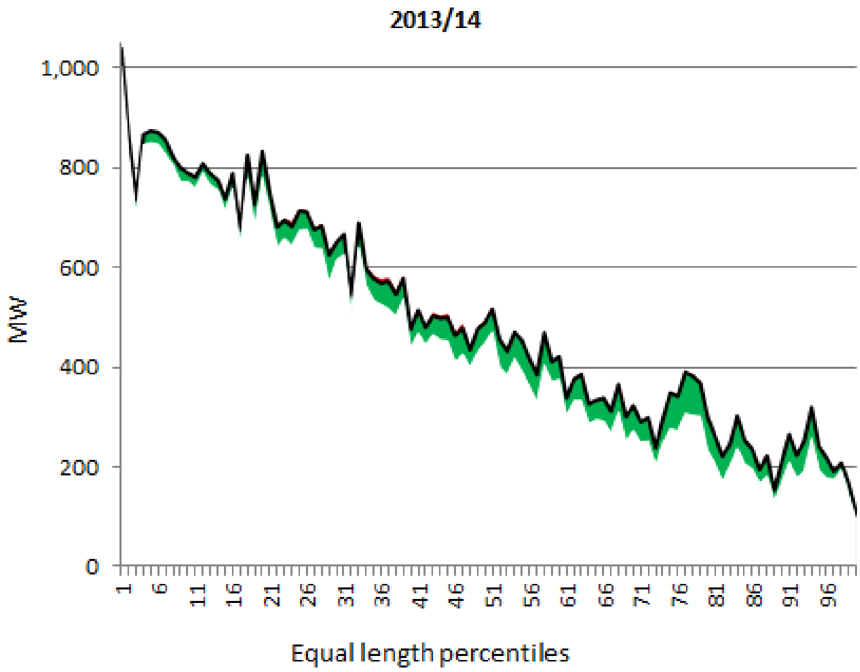
4.80 A Workgroup member stated that Peterhead is generating in the graphs and as such it cannot be suggested that they would not be contributing at all to constraints. The proposer agreed and explained that Peterhead would continue to make some contribution to causing constraint cost and that Peterhead would continue to pay a very high TNUoS cost to reflect this. CMP268 does appropriately take this into account because the continued application of the ALF to the Year Round tariff would mean that even after CMP268, Peterhead would still be paying amongst the most expensive TNUoS tariffs of any CCGT in GB. A Workgroup member suggested that this was an investment question and part of the Economy Criteria. It was also noted that tariffs are not related to constraints in low diversity zones and that instead they reflect investment cost.

4.81 The proposer went onto explain the Peterhead example. He stated that the data provided earlier within the Workgroup report (4.15), and used for the analysis within EdF's Workgroup Consultation response was not for a long period and in fact a small sample made up of around two to three weeks of generation out of the whole of calendar year 2015. He stated that Peterhead had an outage to upgrade their steam turbine and the limited period for which generation did take place corresponded to dispatch for commissioning and testing purposes following this upgrade. Peterhead had an SBR contract and therefore the operation during this limited period was constrained by the SBR rules. This meant that generation output could only exceed its TEC outside of peak hours, so the small number of half hours in which Peterhead did exhibited its highest output (those periods exceeding 200MWh per half hour) were required to explicitly avoid periods of peak demand. It was suggested that this fully explains why Peterhead's dispatch pattern during those limited number of half hour periods appeared counterintuitive compared with the merit order dispatch which would normally be expected. Therefore Peterhead's dispatch pattern during those few days in calendar year 2015 is not representative how the station could be expected to operate on an ongoing basis in normal commercial conditions and it is not valid to draw any conclusions regarding CMP268 from that limited data set. More information can be found on this below.

4.82 A Workgroup member questioned why the proposer's analysis compared everything against demand and didn't seek to plot the relationships that it was trying to illustrate directly. The Workgroup member said that if he was trying to show a relationship between constraints and Peterhead's output he would have plotted a scatter plot of the two, not plotted both independently against net demand. The proposer stated that it was completed this way to be consistent with the same approach previously used within the Workgroup Consultation Report; also this approach made it clearer to compare different technology types with each other and would have resulted in the same general relationships being demonstrated. Another Workgroup member restated his view that the analysis still didn't show anything as it ignored the fact that, where there are low levels of diversity, the main driver of transmission investment is the total generation capacity (MW) in the relevant zone rather than the volumes of constraints (in MWhs) caused. The Workgroup member also pointed out that as diversity reduces in an area under the current methodology you would allocate a greater proportion of the costs into the non shared charge (ie this is not a binary effect). It was noted that under CMP213 a level of at least fifty percent carbon plant in a zone was decided on being the point when sufficient diversity existed in a zone so that 100 percent sharing could take effect.

Marginal Conventional Carbon Generator (Peterhead) not being "Offered on"

4.83 The proposer present the graph below which shows for Peterhead the combination of FPN, as well as Bids and Offers taken. The volume of bids taken is shaded in green, while the volume of offers taken is shaded red (offer volumes are difficult to see on the graph because the volumes are so low). The proposer said that this illustrates that when Peterhead was operating on a commercial basis within the wholesale market, there was no significant systematic requirement for the System Operator to constrain on (offer on) Peterhead for system reasons. This pattern of dispatch is consistent with generation volume metered data.



Longannet operational characteristic

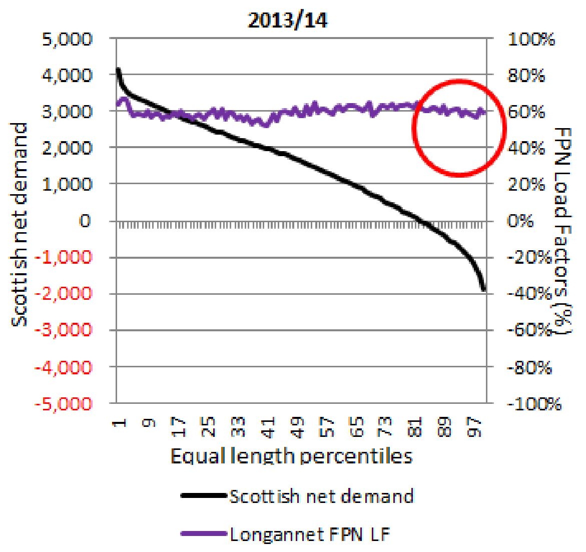
4.84 The graphs below illustrate Longannet FPNs compared with the volume of Bids and Offers which were taken. These results shown further support the proposed CMP268 approach of applying Conventional Carbon generator's ALF to their Not Shared Year Round tariff instead of the 100% used within the Baseline.

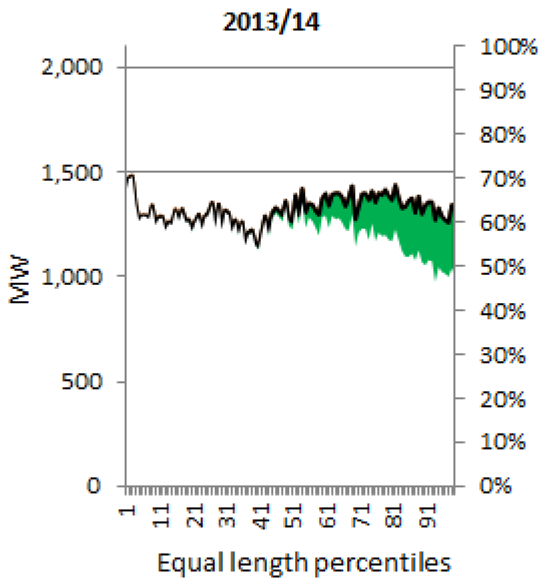
4.85 The volume of Bids taken (reduced output) are shown in the green shaded area. The volume of Offers taken to increase output are shown in the red shaded areas, note this it is difficult to see these volumes on the graph because the volumes were relatively small.

4.86 The proposer stated that this analysis illustrates that in all years, Longannet's average load factor during periods when constraints are most likely tended to be in the range of 30% to 60% which is substantially lower than its full capacity.

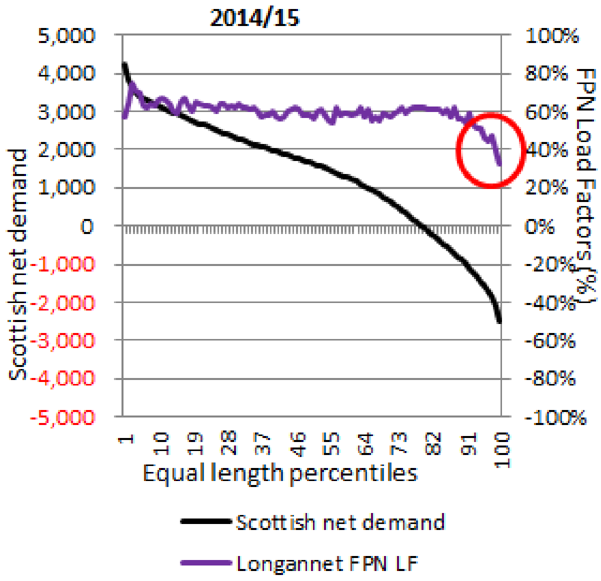
4.87 Further the analysis shows the average bid volume during those periods tended to reduce Longannet's generation load factor further by up to 20% compared with its FPN. The proposer stated that this is an illustration of periods when Longannet could be bid off at a relatively low cost (compared with Low Carbon generation such as wind or nuclear) to avoid constraints. This historical dispatch pattern of either avoiding periods when constraints are likely to take place, or of being bid-off is consistent with the principles of sharing that were outlines in the CMP213 Workgroup Report and consistent with CMP268.

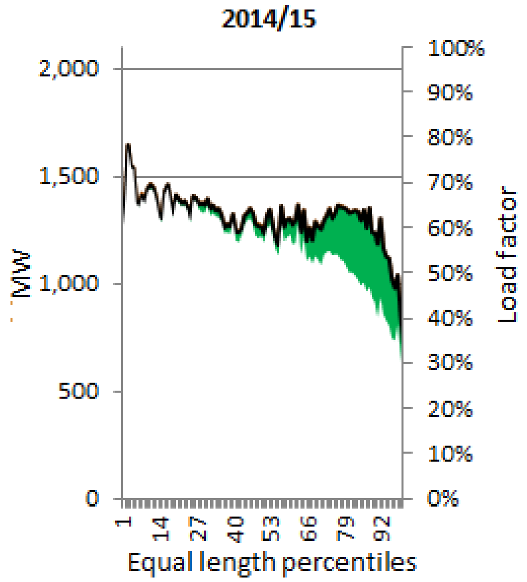
4.88 The proposer stated that it would appear that the generation output of Longannet after bids had been taken tended to be higher than that for Peterhead (30% to 50% for Longannet, compared with 0% to 20% for Peterhead), so it may be concluded that the operational characteristics of Longannet tended to cause more constraints than Peterhead. This result is consistent with the respective ALFs of the two stations, for 2016 with Longannet at 55% and Peterhead at 42%[14] and consistent with the way the ALF would be applied in CMP268.

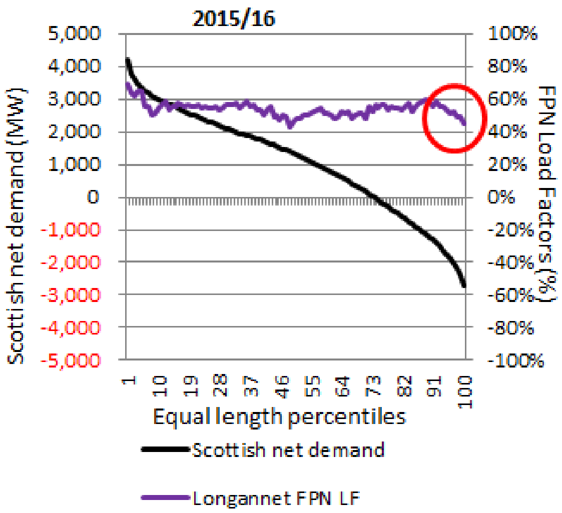




[14] Annual Load Factors for 2016/17 Generation TNUoS Charges, National Grid January 2016 http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/


2014/15
Scottish net demand
FPN Load Factors (%)
Equal length percentiles
Scottish net demand
Longannet FPN LF


2014/15
MW
Load factor
Equal length percentiles


2015/16
Scottish net demand (MW)
FPN Load Factors (%)
Equal length percentiles
Scottish net demand
Longannet FPN LF

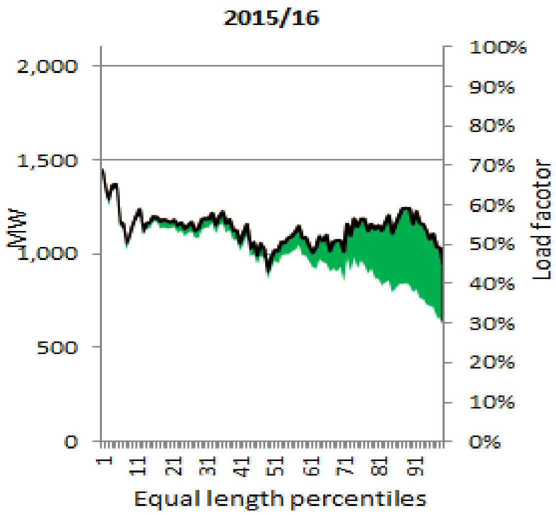

2015/16
MW
Load factor
Equal length percentiles

Illustration of the feedback loop created by the Baseline application of the Not Shared Year Round tariff element

4.89 The proposer stated that SSE carried out analysis using the ICRP Transport Model for 2017/18 as published by National Grid to accompany the June 2016 Quarterly Update 2017-18 to derive locational TNUoS tariffs across a range of sensitivities. The Model was used as published with the following adjustments to test sensitivities:

1. Variation of MW capacity of Conventional Carbon Generation in Scotland, specifically Peterhead, Foyers and Cruachan. The sensitivity was applied to all three on a pro-rata basis to avoid making any judgement regarding particular station investments.

2. Increase in MW capacity of wind farms in Scotland

Baseline treatment of Not Shared Year Round tariff element causes a feedback loop

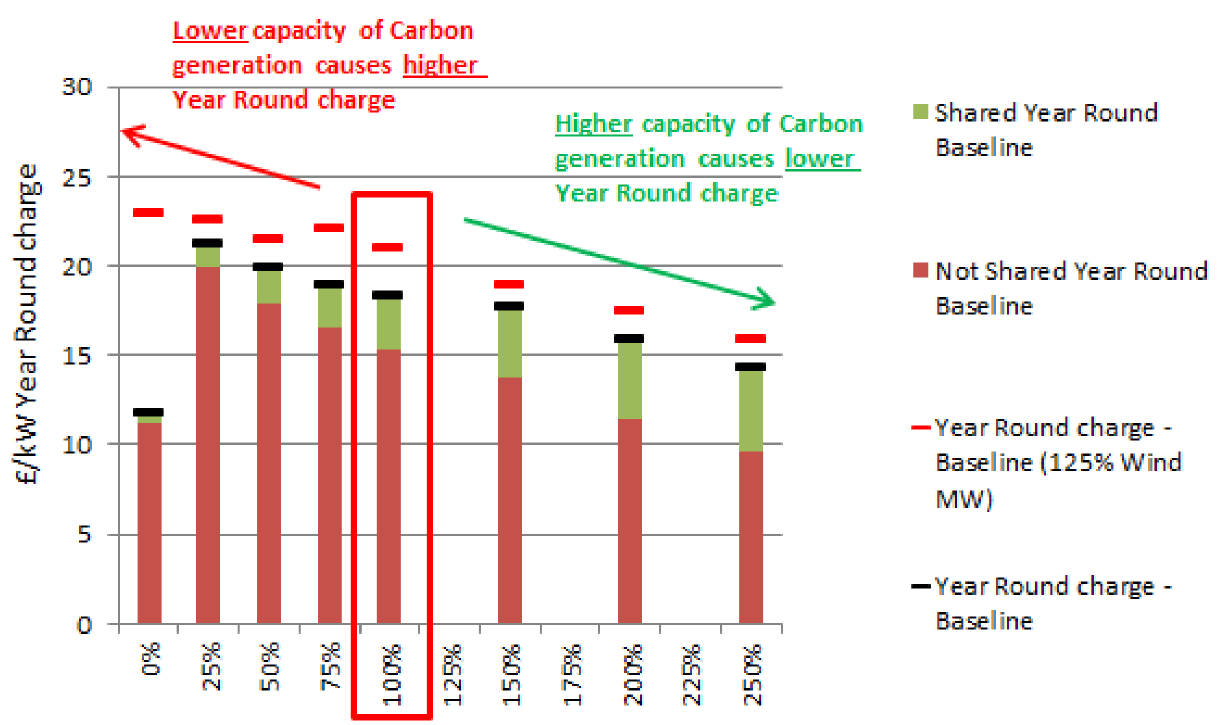
4.90 He stated that the graph below illustrates the feedback effect which tends to be caused by the application of the Baseline Not Shared Year Round tariff methodology. This shows the impact of sensitivities to the installed capacity of Carbon generation in Scotland (Peterhead, Foyers and Cruachan) as compared with the capacity listed in the National Grid published ICRP Transport model associated with the June Quarterly update of TNUoS tariffs for 2017/18. The x-axis shows the sensitivity assumption regarding pro-rata adjustment to the installed capacity of Carbon generation in Scotland ranging between 0% and 250% of the National Grid published capacity (100% is equal to the National Grid published capacity).

4.91 He stated that this demonstrates that the Baseline combined Year Round charge tends to become more expensive as the capacity of Carbon generation is reduced because this causes a reduction in assumed sharing, so a relative increase in the proportion of the Year Round tariff which is defined as “Not Shared”, on which Conventional Carbon generators currently pay 100% of their TEC. This tends to create a feedback loop because the higher share of the “Not Shared” element tends to an increase in the combined Year Round charge, which tends to provide an even stronger price signal for the remaining Conventional Carbon generators to also close. The reverse is also the case that the higher the capacity of Conventional Carbon generators locating in Scotland would tend to cause a reduction in the combined Year Round charge, which would tend to make Scottish zones relatively more financially attractive for future additional Conventional Carbon generators, so tend to create a feedback loop of additional investment.

4.92 In addition he stated that the horizontal red bars show the same result, but using the additional sensitivity assumption of a 25% increase in the capacity of wind in Scotland. This sensitivity highlights that with the additional wind capacity, the feedback loop of increasingly expensive Year Round charges would continue all the way down to a zero capacity of Conventional Carbon generation in Scotland.

4.93 He noted that the graph below illustrates this feedback effect on the Year Round TNUoS charges within the Baseline CMP213 WACM2 charging methodology for a Conventional Carbon generator with an ALF of 25% in Charging Zone 1.

Components of Baseline Year Round charge for a 25% ALF Conventional generator



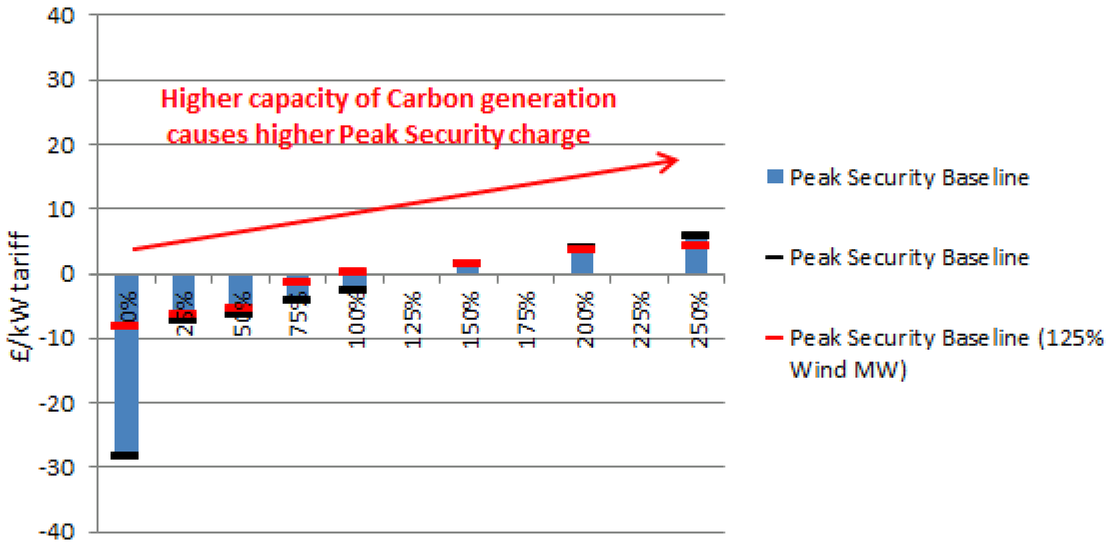
Sensitivity capacity of Scottish Conventional Carbon capacity Vs NG published 2017/18

4.94 A Workgroup member noted that should plant close in a certain area that this would not necessarily mean that this would give a signal for other plant to close in the same area simply due to an increase in tariffs caused by the diversity calculation in the charging methodology. He went onto explain that there were a number of additional economic aspects that would be more likely to be taken into consideration before making this decision. These include where you are located in the network and how efficient and reliable your plant is.

4.95 The Proposer suggested that a key characteristic of effective market price signals is that the magnitude of price signals should become weaker when market participants respond to them and in this way the price signal could be expected to incentivise the market to tend towards an “equilibrium”. By contrast, the application of the Not Shared Year Round tariff element provides the opposite result since the tariff price signal (lower, or higher tariffs) becomes stronger as more Conventional Carbon generators respond to it which will tend to incentivise the market to move progressively further away from an ‘equilibrium’ in terms of tariffs and locational investment decisions. This tendency away from equilibrium occurs because if the capacity of Conventional Carbon generation in the Scottish zone is reduced, then the Year Round charge becomes more expensive, so provides a stronger incentive for even more additional capacity to move away from that zone and the same feedback loop effect occurs in the opposite direction if more Conventional Carbon is added to the zone.

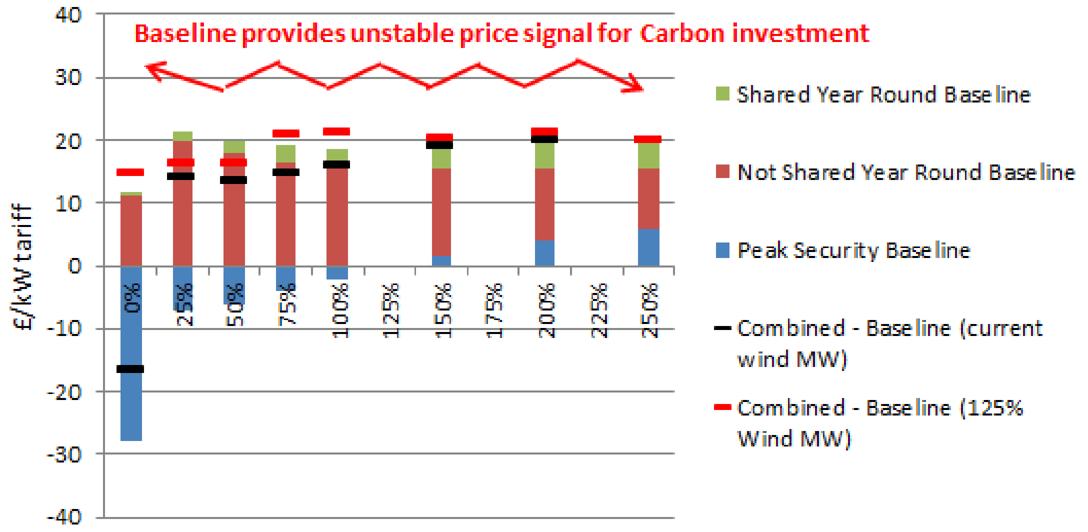
Baseline Peak Security tariff tends to provide opposite price signal to Baseline Year Round

4.96 The proposer stated that the graph below takes the same approach as the graph above, illustrates the impact of the same scenarios for the Peak Security tariff element. This demonstrates that as the Capacity of Conventional Carbon generation reduces, the Peak Security price signal tends to become cheaper i.e. it tends to provide an increasingly strong incentive for Conventional Carbon plant to locate in Scottish zones to reduce the cost of the network with regard to investment required to provide Demand Security.



Baseline combination of Year Round and Demand Security tariff elements provide unstable incentives

4.97 He noted that the graph below illustrates the issue that signal arising from the methodology for calculating the large positive Baseline Not Shared Year Round charge tends to be large enough to drown out the opposite price signal provided by the negative Peak Security tariff. The net charge tends to be unstable and does not to provide an incentive to tend towards an equilibrium balance of Conventional Carbon plant i.e. there is not a systematic relationship between a higher or lower capacity of Conventional Carbon plant and a resulting change in TNUoS locational price signal. This is an undesirable characteristic for a price incentive mechanism.



CMP268 does provide price signal that leads to a rational incentive for investment to converge to equilibrium

4.98 The proposer stated that the same tariffs were applied using the proposed CMP268 tariff formula with the resulting charges for a Conventional Carbon generator as illustrated in the graphs below. He believes that this demonstrates the following beneficial characteristics of proposal, CMP268:

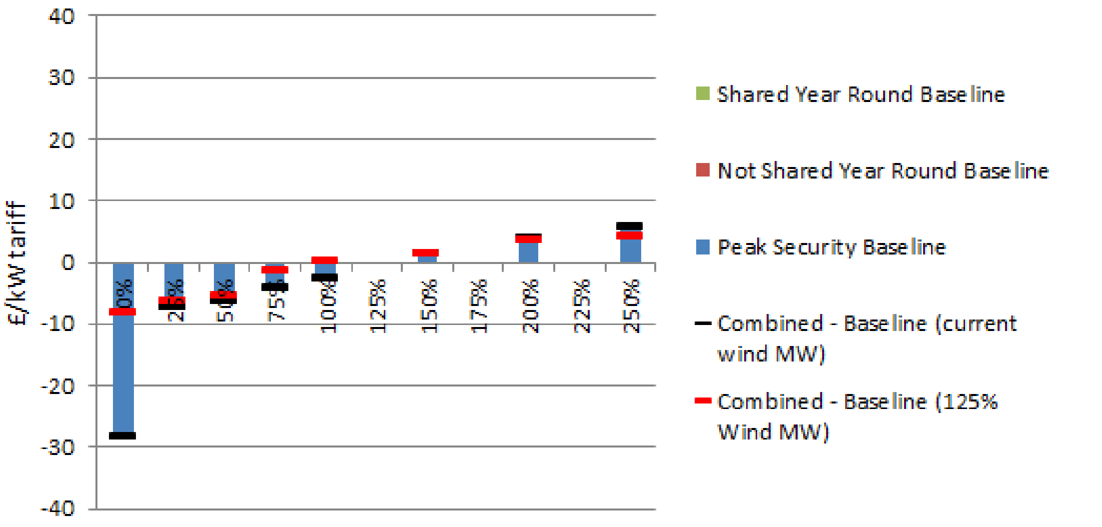
1. **Price signals tend towards equilibrium –** In contrast to the Baseline charging methodology, the set of price incentives provided by CMP268 do tend towards an economic equilibrium. This occurs because the transmission price signal for Conventional Carbon generators in Scotland tends to become more expensive when more capacity is built and correspondingly cheaper when capacity is closed.

2. **More appropriately different charges for different generators** – Graphs below illustrate:
    a. **For a 0% ALF generator** - The price signal it receives is driven by the Peak Security tariff element, which the proposer considered is consistent with the SQSS treatment of OCGTs. The proposer felt that this illustrates that if there were to be a closure of dispatchable generation in Scotland, then the price signal would tend to change to provide a stronger incentive to invest in low load factor peaking plant in affected zones. The proposer felt that this is consistent with the intuitive result that a zone dominated by wind generation would tend to be a relatively good location (from a network cost point of view) to locate a low load factor peaking generator.

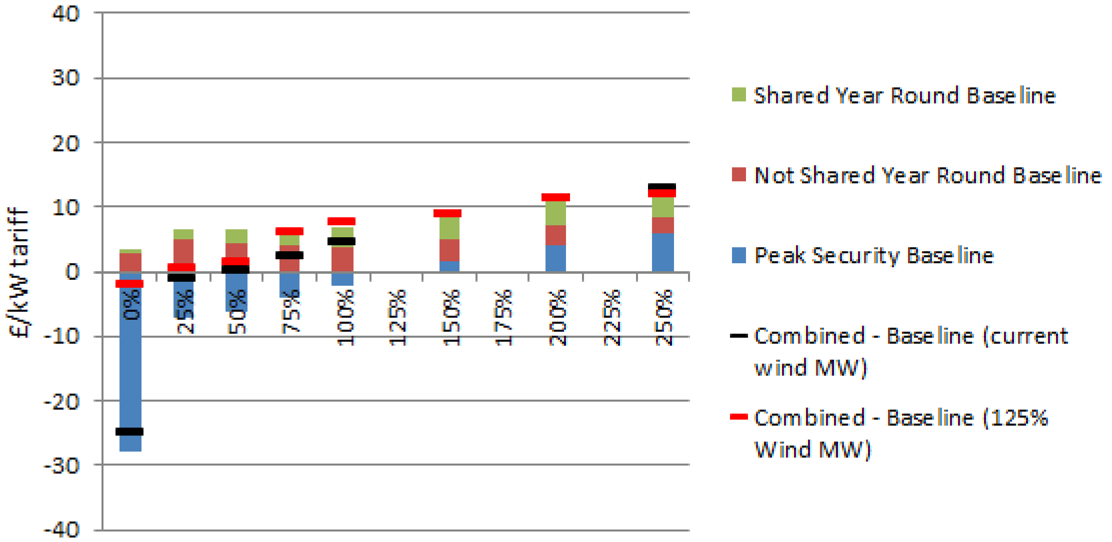
    b. **For a 25% ALF generator** – The price signal it receives is a balance of the Peak Security and Year Round tariffs. The proposer felt that this appropriately demonstrates that if the capacity of Conventional Carbon generation in Scotland reduced, then the negative Peak Security price signal would become increasingly dominant, while if the capacity of Conventional Carbon generation in Scotland increased, then the more expensive positive Year Round charge would tend to become increasingly dominant.

c. **For a 75% ALF generator** – The price signal remains expensive for this type of generator (such as a high efficiency new entrant CCGT) in Scotland across almost all scenarios. The proposer felt that this is consistent with the intuitive result that a zone dominated by wind generation would tend to be a relatively poor location (from a network cost point of view) to locate a high load factor baseload generator.

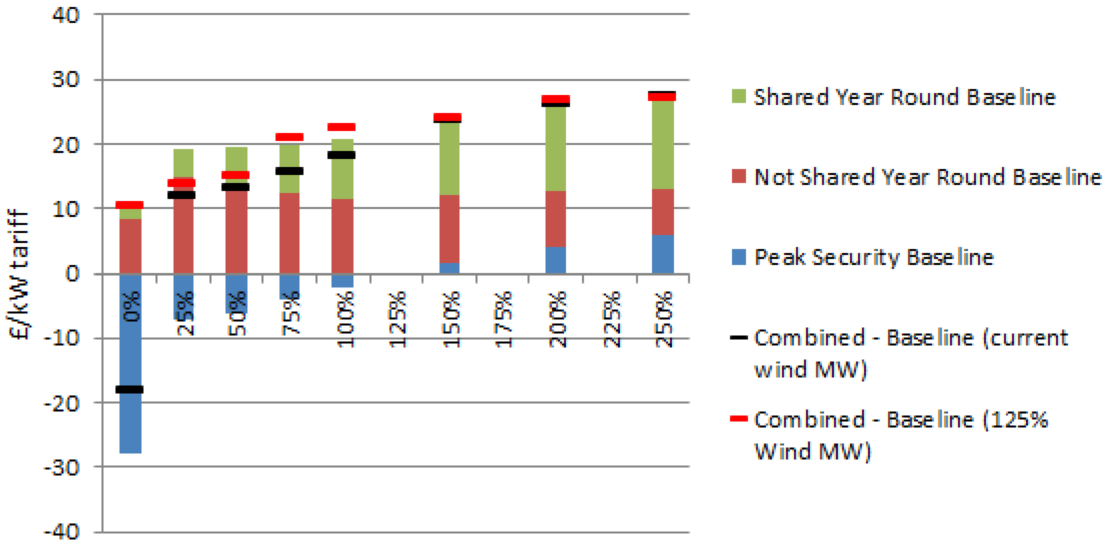
CMP268 - 0% ALF



CMP268 - 25% ALF



CMP268 - 75% ALF



4.99 A Workgroup member stated that the graphs above do not show any instability, but simply show that the cost drivers on this part of the network are more complex. The Workgroup member considered that in this area of the network you have a lack of diversity which is pulling the cost in one direction to one equilibrium and the effect on north south flows on the rest of the network which is pulling the charge in another direction to another equilibrium. The direction the overall charge goes in response to an investment decision depends on which driver has the dominant effect under those set of circumstances. He went onto state that the locational signals are consistent with what you would expect to see and that this is simply the nature of how complex the factors are which determine the cost of the network and are reflected in the charging model. He went on to state that this is no different to what happens elsewhere in the methodology. For example a station in the south with very low tariffs will have some circuit costs which are negative and some which are positive. A change in its flows may increase costs in some circuits and decrease costs in others in the model. The effect on charges depends on which effect is the greater. Another Workgroup member felt that the graphs provided did not illustrate anything to support CMP268.

4.100 It was suggested by one Workgroup member that the analysis provided suggests that there is a case for addressing or looking at some fresh analysis for load factors, diversity and in addition sharing and that this should be carried out within a wider review of this mechanism and cannot be done within the defect stated as the justification for this modification. It was noted that what may benefit one category of plant may have an adverse effect on others and in addition may give a competitive advantage to one category of plant without analysing the wider picture within this modification.

4.101 The Workgroup has had limited time to assess the additional information presented by SSE post consultation. The Workgroup has not undertaken any of its own work, and that to assess properly the information we would need to undertake this work. However the terms of reference and the urgent timescales prevent the Workgroup from undertaking such work.

5 Impact and Assessment

Impact on the CUSC

5.80 Changes to CUSC Section 14 – Part 2 – The Statement of the Use of System Charging Methodology,

5.81 Changes to CUSC Section 14 Section 1 – The Statement of the Transmission Use of System Charging Methodology

Impact on Greenhouse Gas Emissions

5.82 None identified.

Impact on Core Industry Documents

5.83 None identified.

Impact on other Industry Documents

5.84 None identified.

6 Proposed Implementation and Transition

6.1 The Workgroup discussed how the proposed arrangements would transition and be implemented. The details of their proposed implementation and transition are shown in this section.

Implementation timeline

6.2 New tariffs are to be applied from 1 April 2017. It is proposed that the new tariff formula arising from CMP268 should apply from charging year starting 1 April 2017.

6.3 The Authority have granted an urgent status for this Proposal on the basis that an Authority decision should be reached by the end of November to provide certainty for market participants placing bids in the T-4 Capacity auction for 2020/21 which is expected to take place in the first week of December 2016.

6.4 National Grid Draft TNUoS tariffs (December 2016) – If a decision is not published by the time Draft Tariffs are due to be published National Grid will publish two scenarios for Generation Tariffs; Status Quo and CMP268.

6.5 If decision is not published by end of January 2016 then this will require a mid-year tariff change.

6.6 The Workgroup discussed how the proposed arrangements would transition and be implemented. The details of their proposed implementation and transition are shown in this section.

System Changes

6.7 There will be no System Changes for Industry. All required changes made will revolve around changes to National Grid's internal billing System. As discussed within the report, the System will now require an extra attribute to recognise the concept of Carbon and Low carbon, and the combination of this with Peak (Conventional), will alter how the Year Round not Shared Tariff is calculated for those particular Generators.

Costs to Implement

6.8 National Grid have requested a quote from the providers of our current billing system to undertake the change but due to the timescales of this modification this has not yet been received so cannot be provided within this consultation. Further consultation reports will have an updated figure. For reference Project Transmit was quoted at ~£1million. This System change will not be in that magnitude. As changes for Project Transmit have only recently been tested and implemented a change so soon afterwards is inefficient.

Communications

6.9 This modification directly affects a limited number of Generators from a locational TNUoS perspective. National Grid will contact them directly to make them aware of this modification. All Generators will see a change in the Residual element of their tariff (please see analysis) but only in the magnitude of changes historically seen between quarterly forecasts of tariffs. Therefore communication for these Generators will be via the Quarterly forecasts and the National Grid Customer Account Managers.

7 Workgroup Consultation responses

7.1 The Workgroup Consultation closed on 30th September 2016 and received five responses, including one late response. A summary of these responses can be found below; the full responses are included within Annex 7.

Respondent	Do you believe that CMP259 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?	Do you support the proposed implementation approach?	Do you have any other comments?
SSE	**Objective "a" effective competition** – Yes CMP268 does better facilitate effective competition for the reasons already outlined in the Workgroup consultation. **Objective "b" cost reflectivity -** Yes CMP268 does better facilitate effective competition for the reasons already outlined in the Workgroup consultation.	Yes. Please see the full responses in Annex 7 for all the benefits outlined by SSE to the implementation approach suggested.	Please refer to the full response in Annex 7 for analysis provided to support the modification.
Uniper	No we do not. This modification would act against charging objectives a) and b). The problem with CMP268 is that it is based on a misunderstanding about the basis for the present charging methodology. To understand how the current Shared and Not Shared charges came about, it is necessary to review the history of how CMP213 came to establish these charges.	No.	No.
Drax Power	No. We believe that CMP268 would adversely affect the Applicable Objectives (a), (b) and (c).	No, the modification has been conducted under urgent timescales and therefore a proper assessment of whether CMP268 improves cost reflectivity has not been done.	Table 1 on page 37 could be misleading (this has been updated since Workgroup consultation)
EDF Energy	We do not believe the proposal can be approved. There is too little time available for an evidence-based decision to be made on re-opening CMP213, bearing in mind the depth of expertise and duration of study that was brought to bear on the review of transmission charging during Project TransmiT.	We do not believe that this modification should be implemented; if it were, at least two years' notice is needed before implementation of such a material change. Implementation from	No.

	We know that the 'defect' asserted by the proposer was explicitly considered in CMP213 and a balanced decision was made to adopt the current diversity method. We believe that re-opening a single issue within the overall framework of the diversity method is unjustified. We have anyway strong doubts about the cost-reflectivity of the proposal, which asserts benefits arise from 'sharing' transmission in wind-dominated zones, based on our evidence of both Scottish pumped storage and Scottish gas-fired generation running more during times of high Scottish wind output than low.	April 2017 is certainly not appropriate.	
RWE	We do not believe that CMP268 Original proposal or any potential alternatives for change better facilitates the Applicable CUSC objectives. The CMP213 Workgroup undertook rigorous analysis of the issue of sharing. Ofgem determined that the approach adopted was cost reflective and better met the applicable CUSC objectives. We have seen no new evidence that CMP268 is more cost reflective than the current baseline.	No –we do not believe that this modification should be implemented.	We are concerned that the urgent timescale prevents detailed consideration of the potential alternatives to sharing identified by the CMP213 Workgroup. The alternative methods may better address the alleged defect than the approach identified under CMP268.

8 Views

8.1 Following the Workgroup discussions and discussions around the Workgroup Consultation responses there were no Workgroup Alternative CUSC Modifications proposed by the workgroup.

8.2 It was noted that some Workgroup members felt that the urgent timescales around this modification have dictated the fact that they have not been able to propose any alternatives. A review of the CMP213 options has not been undertaken and it was suggested that there could be a number of options that could have been explored should time have allowed the group to do so.

8.3 One Workgroup member stated that should the modification be approved a modification would be raised soon after to address Sharing.

Workgroup voting and conclusions

8.4 The Workgroup believe that their Terms of Reference have been met whilst noting some Workgroup member's comments at various points throughout the report on the restrictions due to timescales of the modification.

8.5 At their meeting on 12th October 2016, the Workgroup voted. One Workgroup member voted that the Original proposal better facilitated the applicable CUSC objectives and five members voted for the baseline.

For reference, the Applicable CUSC Objectives are;

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

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

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

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

(e) promoting efficiency in the implementation and administration of the CUSC arrangements.

Workgroup Vote

Vote 1: Whether each proposal better facilitates the Applicable CUSC Objectives;

Original Proposal

Workgroup member	Applicable CUSC Objective					Overall
	(a)	(b)	(c)	(d)	(e)	
John Tindal	Yes	Yes	Yes	Yes	Yes	Yes
Damian Clough	Neutral	Neutral	Neutral	Neutral	Neutral	No
James Anderson	No	No	Neutral	Neutral	Neutral	No
Paul Jones	No	No	No	Neutral	Neutral	No
Bill Reed	No	No	No	No	No	No
Paul Mott	No	No	No	Neutral	Neutral	No

Vote 2: Whether each WACM better facilitates the Applicable CUSC Objectives than the Original Modification Proposal;

Due to there being no WACMs proposed, this vote is not applicable.

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

Workgroup member	BEST Option
John Tindal	Original
Damian Clough	Baseline
James Anderson	Baseline
Paul Jones	Baseline
Bill Reed	Baseline
Paul Mott	Baseline

The Workgroup were asked to provide commentary on why they voted as above. Commentary received is as below;

Paul Mott:

There was too little time available for an evidence-based decision to be made on re-opening CMP213 and diversity method 1, bearing in mind the depth of expertise and duration of study that was brought to bear on the review of transmission charging during Project TransmiT. The cost-reflectivity of the proposal is in grave doubt: at times when (asynchronously-connected, and thus lacking in inertia) wind output is high in export-constrained areas with abundant low carbon generation, there is likely to be a need to ensure that what little carbon-based generation is left, is running, due to growing concerns (a recent development on the transmission system influenced by what's connected to it, as a whole system) over the growing national issue of inertia and frequency management, and local system issues. CMP268 not being cost-reflective, it will be re-distributive in a manner that is unwarranted, and thus harmful to competition.

Bill Reed:

The introduction of sharing to the non-shared component of the tariff undermines the approach adopted for generation tariffs under CMP213. The CMP213 “Method 1” clearly establishes the principle that sharing between carbon and low carbon generators up to a defined level is based on the applicable load factor (ALF), and that beyond this level the capacity of the generators in a zone determines the non-shared investment signals applicable to the relevant parties. Therefore the non-shared component of the tariff cannot be shared by reference to the ALF.

Paul Jones:

This will distort the arrangements away from what was agreed to be the cost reflective approach during CMP213. Lack of diversity in a zone was demonstrated to drive investment to be that to meet near to 100 percent of the total generating capacity within that zone; both low carbon and carbon plant, rather than based on constraint costs driven by load factor. This is why analysis used to illustrate that low load factor carbon plant drive lower levels of constraint costs is not relevant for low diversity zones.
This is what the present charging regime reflects. The signals are correct. If the diversity increases in the zone then a greater proportion of the cost of the assets goes into the shared charge. Similarly, if it decreases then a greater proportion of the cost goes into the non-shared charge. The proposal will move away from this and distort the cost signal.

We also note the additional late analysis that the proposer has presented on SQSS sharing factors and consider that it is fundamentally flawed as it is looking at weighting factors used for deterministic analysis on the system and comparing them with load factors are used for charging. This is not a like for like comparison.

This modification if implemented would provide a significant cross-subsidy to a small subset of stations which would result in a distortion to the wholesale energy market and, more significantly, in the forthcoming Capacity Market auction. This would have significant consequences for competition and could threaten security of supply depending on the plant that is displaced due to this distortion.

James Anderson:

The evidence presented by the Proposer appears to indicate that for the particular class of generators identified as “Conventional Carbon”, the Charging Methodology may not be fully cost reflective. However, without a detailed examination of how and why the relationship between load factor and constraint cost identified under CMP213 breaks down under various circumstances including the prevalence of Low Carbon plant it is not clear that the proposed solution of applying the ALF to the Non-Shared Year Round tariff under CMP268 would overall be more cost reflective than the current baseline. The proposal therefore does not better facilitate applicable charging objective (b).

The key deliverable of the TNUoS Charging Methodology is that it delivers cost-reflective charges which will facilitate efficient economic decisions and thereby effective competition. As it is not clear that CMP268 will overall deliver more cost reflective charges than the baseline it will therefore not better facilitate applicable charging objective (a).

The proposal is neutral against objectives (c) and (d) and although it may add a small amount of additional complexity to the charging and billing arrangement, is neutral against objective (e).

Overall, the proposal will not better meet the applicable charging objectives than the current baseline.

John Tindal:

Vote 1

a) **CMP268 Original better facilitates competition in the Capacity Market and also the wholesale power market**. This is because CMP268 Original removes a pre-existing non cost reflective economic disadvantage which is currently faced by a small number of Conventional Carbon generators who are located in charging zones with a substantial positive Not Shared Year Round tariff element, or potential new generators who may consider developing in such a location in the future. A failure to correct this defect would result in those generators continuing to face excessively expensive TNUoS charges which are not justified by cost reflectivity and therefore mean they would not be able to compete on a level playing field in particular with regard to the Capacity Mechanism. CMP268 Original also results in a more level playing field for competition with regard to Conventional Carbon generators located in charging zones with a negative Year Round Not Shared tariff.

b) **CMP268 Original is better regarding cost reflectivity with regard to the cost incurred by transmission licensees in their transmission businesses**. In context, the cost reflectivity of CMP213 was substantially better than the previous baseline through the introduction of the combination of the dual background, ALF and calculation of diversity. CMP268 further improves on the cost reflectivity of CMP213 by making a small change to the application of the tariff formula which directly affects only a small minority of generators i.e. only those generators classed as Conventional Carbon who are also exposed to a significant non-zero Not Shared Year Round tariff element. This better cost reflectivity arises by better reflecting the fact that Conventional Carbon generators do continue to share all Year Round circuits even if they are located in a zone where the power flows may be dominated by Low Carbon generators. This is why the incremental investment cost which they cause remains a function of their ALF on the whole Year Round tariff and by contrast, is not reflected by the current baseline approach of applying 100% of their TEC to the Not Shared Year Round tariff element. This sharing is most clearly understood by considering the two key principles which were behind sharing as laid out during the CMP213 Workgroup process, where the degree of sharing is a function of two key characteristics:

i. **Firstly, the degree of correlation with periods of constraint** – Conventional Carbon generators will tend to choose to dispatch to **avoid** generating during periods when constraints are most likely to occur because these periods will also tend to be associated with relatively low power prices caused by a simultaneous occurrence of relatively high wind volumes combined with relatively low demand. The lowest ALF Conventional Carbon generators (e.g. OCGTs, or other peaking plant) will tend to exhibit dispatch patterns with the lowest likelihood of dispatching during periods when constraints are most likely to occur, while higher ALF generators (e.g. high efficiency new entrant CCGTs) may be more likely to tend to dispatch more often during periods when constraints may occur and this difference between lower ALF and higher ALF generators is reflected within CMP268 by the continued application of their ALF to the whole Year Round tariff element. This dispatch pattern is borne out by economic theory of merit order generation dispatch and also borne out by empirical analysis of historic generation dispatch data. For the avoidance of doubt, this positive sharing characteristic of Conventional Carbon generators continues to take place even if they are located in a charging zone with a non zero Not Shared Year Round tariff.

ii. **Secondly, the cost of being "bid off"** - Even if a conventional Carbon generator may be occasionally operating during a period when there is a risk of network constraints, then it tends to be available to be "bid off" to relieve the constraint at a relatively low cost to the System Operator. For the avoidance of doubt, this positive sharing characteristic of Conventional Carbon generators continues to take place even if they are located in a charging zone with a non zero Not Shared Year Round tariff.

For the avoidance of doubt, even if some Conventional Carbon generation may be required to operate by the System Operator for system stability reasons, then this is not a valid justification for charging Conventional Carbon generators as if they don't share the transmission network. Firstly, as illustrated by the additional evidence provided by SSE, in practice historically, the sharing behavior has continued to take place. Secondly, as described in the CMP268 Workgroup report, any dispatch which may be required for system reasons **does not represent an incremental cost** of network investment for the bulk supply of energy, so it should not form part of TNUoS charges and this is clearly explained within Section 14 of the CUSC:

*c) "The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the **incremental costs** of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs**, if they were to increase or decrease their use of the respective systems**. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure **bulk supply of energy**." (*paragraph 14.14.6) [emphasis added]

The evidence for the better cost reflectivity of the CMP268 Original was clearly presented in during the CMP213 process which included substantial in depth expert analysis and a collection of this previous detailed analysis was provided to the CMP268 Workgroup at the start of the CMP268 Workgroup process. The proposer also presented an interpretation of this previous analysis and some additional new analysis to further illustrate the better cost reflectivity of CMP268.

It is the Proposer's view that there is already sufficient existing detailed analysis which supports the better cost reflectivity of CMP268 and that further new analysis or evidence should not be required.

d) **CMP268 Original better takes account of the developments in transmission licensees' transmission businesses**. This is because the increasing development of Low Carbon generation (e.g. wind) in Northern zones is tending to cause the Not Shared Year Round tariff element to represent an increasingly large proportion of the total Year Round tariff element, which is causing the Baseline Year Round element of charges to become increasingly expensive, even for low ALF peaking Conventional Generators. This effect has been compounded by the recent closure of some Conventional Carbon generation capacity in Scotland which further increased the cost of the Not Shared Year Round tariff element for low ALF peaking Conventional Carbon generators. At the same time, the Peak Security tariff element in some charging zones of Scotland is forecast (National Grid) to provide a low, or negative price signal indicating a relative shortage of peaking plant in those zones, however, within the Baseline methodology, this negative Peak Security price signal is being crowded out and will continue to be crowded out by the relatively expensive Not Shared Year Round tariff element. Therefore within the Baseline charging methodology, there is currently no way to effectively provide a price signal for low ALF peaking Conventional Carbon generators to locate in those Scottish zones with a low, or negative Peak Security tariff in order to benefit the transmission network from a peak security point of view.

   It follows that a key benefit of CMP268 Original is that it will provide a more appropriate and more cost reflective set of price signals for Conventional Carbon generators with different ALF characteristics. In particular, a low load factor peaking Conventional Generator with a low ALF will face a TNUoS price signal which will tend to be dominated by the Peak Security tariff element in a way which it is not currently within the Baseline. By contrast, a relatively high ALF Conventional Carbon generator will face a TNUoS price signal which will tend to continue to be dominated by the Year Round tariff element in a very similar way to how the Baseline currently operates. This more cost reflective set of TNUoS tariffs will therefore better incentivise new and existing Conventional Carbon generators to make more efficient investment/closer decisions which better respond to changing developments and circumstances across the transmission network.

e) **CMP268 Original is better because it is more clearly compliant with Objective d**. This is due to applying charges which are more cost reflective and which therefore reduces the degree of existing unjust economic disadvantage currently experienced by a particular group of generators.

f) **CMP268 does better promote efficiency in the implementation and administration of the CUSC arrangements.** This is because CMP268 Original provides a set of TNUoS charges which are more cost reflective and it does so in a way which requires negligible additional administrative burden. Therefore the overall efficiency in the implementation of CUSC arrangements is better.

Vote 3

Same justification as described for Vote 1.

Damian Clough

a) It is important for competition that Generators face charges which accurately reflect the impact they have on the system and other users. Where charges do not reflect costs this can distort competition. Given the timescales involved within this modification, coupled with other concurrent modifications, we are not in a position to vote either way, due to the possible unintended consequences of doing so, which need to be fully assessed and thought through carefully. We are in full support of the principles of CMP213, and are not convinced that there is existing evidence to support this modification change as an natural extension of the principles of sharing, without unravelling the principles of sharing.

b) As quoted in Ofgem's decision letter on CMP213, "it will never be possible to exactly capture the impact of an individual generator on the system while remaining within the principles of the ICRP methodology. Balancing accuracy with the simplicity and transparency of tariffs is an important part of the ICRP methodology because of the impact these factors have on competition". Similar to the response for a), in the timescales involved we are not yet convinced that the defect is not due to the aim for simplicity rather than an explicit defect. The workgroup at CMP213 recognised that in zones where sharing was close to 0% the relation between the SQSS and investment decisions was not as strong. Moving one step further and reflecting Generation types when calculating the Not Shared element of the tariff is an added level of complexity and when you move further in one area, is their justification, to therefore do it for other areas of the methodology. We are therefore neutral to this change at the moment due to the potential unintended consequences of making any change, which requires careful consideration.

The evidence for CMP213 showed that in zones with limited diversity, access to bid prices broke down. It did not clearly distinguish between Generation type.

c) **Neutral**

d) **Neutral**

e) **Neutral:** We are not encouraging a full review of Project Transmit, however it is inefficient to cherry pick a particular aspect of the sharing methodology to the benefit of a select few Generators

Annex 1 – CMP268 CUSC Modification Proposal Form

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP268

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal
Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits
Submission Date
26th July 2016
Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

Description of the defect
The current charging methodology fails to reflect the fact that different types of "Conventional" generation, e.g. CCGTs compared to Nuclear, cause different transmission network investment costs to be incurred due to their different network sharing characteristics.

The defect identified by this modification proposal relates to a type of generating plant which the existing charging methodology defines as being both "Conventional" and "Carbon". For the purpose of simplicity, this modification proposal refers to this group of generators as "Conventional Carbon". To aid understanding of the modification proposal, an explanation is provided in the section below and this ""Conventional Carbon" generator type is highlighted in red in the accompanying table.

The defect is that there is a specific circumstance where the charging methodology is not cost reflective because it fails to recognise that Conventional Carbon plant does in fact continue to fully share all Year Round circuit costs even in circumstances when the proportion of plant which is Low Carbon exceeds 50%. The defect in the current methodology delivers the result that "Conventional Carbon" plant in zones with a significant Not-Shared Year-Round tariff are charged TNUoS tariffs which are higher than the cost they cause and therefore the charging methodology is not cost-reflective for those plant.

Within the current methodology, when the penetration of Low Carbon generators increases beyond 50%, the degree of sharing of Year Round circuits is assumed to linearly reduce for all classes of generation. The current methodology therefore applies the TNUoS tariff elements to all "Conventional" generators in the same way irrespective of whether they are classed as "Carbon" (low constraint cost impact due to low BM bid cost), or "Low Carbon" (High constraint cost impact due to high BM bid cost). This represents a defect because the ability of Conventional Carbon to share with Low Carbon plant actually increases as Low Carbon plant becomes more dominant. The existing charging methodology assumes exactly the opposite relationship and therefore provides incorrect and perverse locational incentives for Conventional Carbon generators within zones with a relatively high concentration of Low

Carbon generators.

Explaining the background to the defect

To understand this modification proposal, it is important to be clear regarding the following terms which have a specific technical definition within the existing charging methodology:

1. Technology type by dispatchability: Classed as either "conventional" or "intermittent" depending on whether they can be dispatched as firm, or non-firm respectively.

2. Technology type by bid price: Classed as either "carbon" or "low carbon" depending on whether they tend to exhibit low cost, or high cost balancing mechanism bid prices respectively due to their short-run marginal cost of generation.

These four classification types were created by CMP213 to enable TNUoS charges to better reflect the different costs to transmission network investment caused by different types of generator. The first classification type of "Conventional" versus "Intermittent" is used by the charging methodology to identify whether a generator can be dispatched on a firm basis, so identify whether or not it pays the Peak Security tariff element. The second classification type of "Carbon" versus "Low Carbon" is used by the charging methodology to adjust the degree of sharing by taking account of the level of diversity as defined by the concentration of "Low Carbon" generation. The table below describes the four potential plant classification combinations and also includes a list of which generation technology types are currently included within each category by the existing charging methodology:

		Technology type by bid price	
		"Carbon" (Assumed low cost BM bid price)	**"Low carbon"** (Assumed high cost BM bid price)
Technology type by dispatchability	**"Conventional"** (Firm dispatch, so pays Peak Security tariff)	**"Conventional Carbon":** CCGT, OCGT, Coal, pumped storage, CHP, biomass	**"Conventional Low Carbon":** Nuclear, hydro
	"Intermittent" (Not firm dispatch, so does not pay Peak Security tariff)	**"Intermittent Carbon"**: No technologies identified	**"Intermittent Low Carbon"**: Wind, PV, tidal, wave

Further detail regarding these four existing classification types is described below

<u>Characterisation by dispatchability</u>

- **"Conventional"** – Stations which are capable of dispatching on a firm basis to meet peak demand. These stations contribute to network flows within the ICRP Transport model Peak Security background, so these stations pay the Peak Security tariff element.

- **"Intermittent"** - Stations which are not capable of dispatching on a firm basis to meet peak demand because they are reliant on a weather dependent source of input energy. These stations do not contribute to network flows within the ICRP Transport model Peak Security background, so these stations do not pay the Peak Security tariff element.

Characterisation by bid price

- **"Carbon"** – This is the name used (for the purpose of CMP213) to identify a class of generating stations that comprises generation plant that is flexible in nature, can reduce/increase output driven by market price and transmission system needs and importantly has a material positive short run marginal cost. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively low cost (positive bid price), so offering a relatively low cost solution to managing constraints.

- **"Low carbon"** - This is the name used (for the purpose of CMP213) to identify a class of generating stations with the purpose of including stations which tend to operate on a "must run" basis, so almost always generate when input energy is available or, for technical reasons are inflexible, irrespective of transmission system need; e.g. demand level. This plant type will tend to bid to the System Operator in the Balancing Mechanism to reduce production at a relatively high cost (low or negative bid price), so offering a relatively high cost solution to managing constraints.

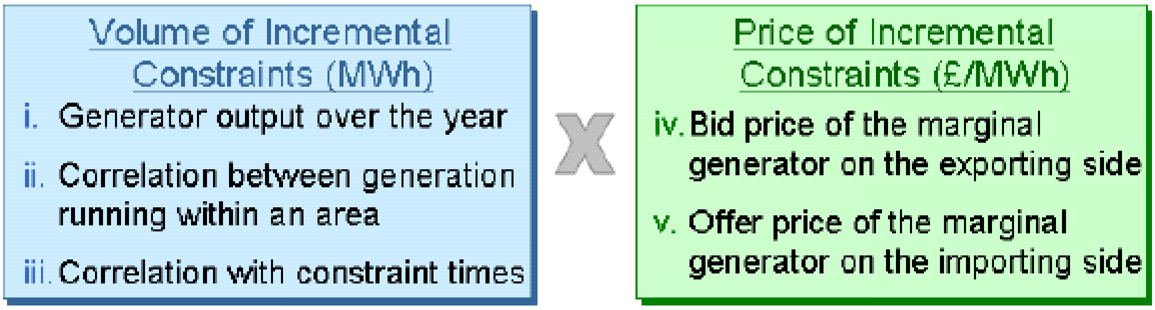
Detailed economic rationale behind the current methodology and this modification proposal

The economic justification for the current methodology was explained in the CMP213 Final CUSC Modification Report found at the following link : http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

The Workgroup report explains that following detailed analysis, the cost/benefit of sharing can be reflected by a generator's Annual Load Factor (ALF), and this approach was implemented in Ofgem's decision to apply a generator's ALF to their Year Round Shared tariff element. This relationship is described below:

> *4.14 From this ELSI based analysis the Proposer believed that a simple proxy for each generator's incremental impact on transmission network costs existed in the form of its ALF, and that this proxy could be incorporated into the existing ICRP approach in order to improve the cost reflectivity of this approach.*

The following illustration is from figure 5 of the CMP213 Workgroup report and explains the different components which drive transmission constraint costs. The "Volume of incremental constraints" is reflected by the station's ALF, while the "Price of incremental constraints" is reflected by the consideration of diversity using the classification of generators between "Carbon" and "Low Carbon" to split the Year-Round tariff between Shared and Not-Shared elements.



The CMP213 Workgroup report goes on to explain the circumstances and causes regarding why network sharing may reduce so that it becomes no longer appropriate to apply the ALF discount. This was described as occurring in zones with a relatively high proportion of Low Carbon generation for the following reason:

> *"4.21 …low carbon plant is more expensive to bid off* ***<u>than carbon plant, which generally has a lower bid price (close to marginal bid price), and is cheaper to constrain off."</u>*** [emphasis added]
>
> *"4.22 The linear relationship between load factor and incremental constraint costs breaks down* ***<u>when bids cannot be taken from plant at close to wholesale marginal price</u>****, and are taken from low-carbon plant instead."* [emphasis added]

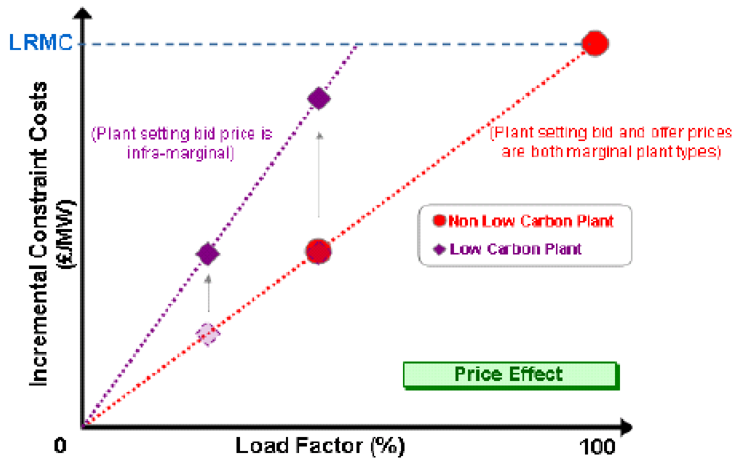


Figure 7 – Divergence in the linear relationship between low carbon and non low carbon plant

It is clear that the CMP213 Workgroup report acknowledged that the reduction in sharing and associated breakdown of the linear relationship with the ALF only occurs when bids can no longer be taken from Carbon Plant. Therefore, <u>it is the absence of Carbon plant which causes the higher constraint costs, not the presence of it</u>. The CMP213 Workgroup carried out analysis to illustrate the following describing the graph below:

> *"4.38 …The red dotted line shows the ideal linear relationship. Mapped against this are the impact of low carbon and carbon generation on this relationship as the percentage of low carbon generation in a zone increases. As the percentage of low carbon plant increases above 50% the cost of bids significantly increases. It follows in these circumstances that incremental low carbon plant increases constraint costs whilst* ***<u>incremental carbon plant reduces incremental constraint costs. This latter effect is because the volume of low carbon</u>***

***plant that runs provides cheaper bids than previously available in that transmission charging zone; i.e. the slope in that zone was previously steeper.*"** [emphasis added]

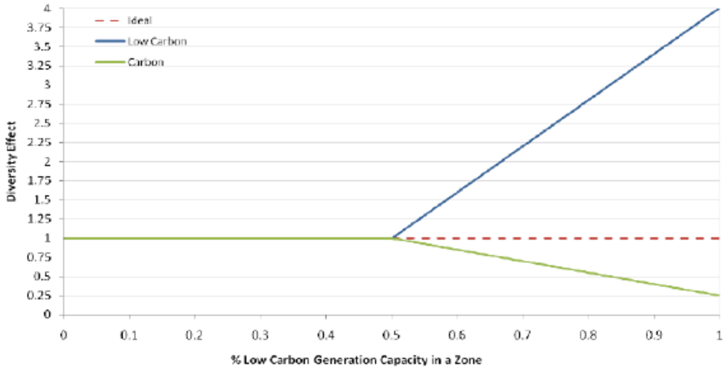


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

It follows that for a Conventional Carbon plant, the impact on constraint cost remains a function of their ALF <u>irrespective</u> of the proportion of low carbon plant it is sharing with because: 1) If in an half hour, the conventional carbon plant is generating, then it is available to be bid off, so a network constraint can be managed at a relatively low cost, so the Conventional Carbon generator is not causing a high constraint cost. 2) If in a half hour the Conventional Carbon generator is not generating, then it is also not causing a high constraint cost.

Clearly, Conventional Carbon plant do not cause the assumed reduction in sharing and they do not cause the assumed higher constraint costs (even in zones with a higher penetration of Low Carbon plant), <u>so it is a defect to charge them as if they do</u>.

Types of harm caused by the defect

If this defect is not corrected, then it will result in at least three key types of harm:

1. Firstly, competition is distorted by a non cost reflective economic disadvantage for Conventional Carbon generators which are located in zones with a high proportion of low Carbon generation.

2. Secondly, the defect will cause higher cost to customers than would otherwise be the case. This is because generators will face the incentive to make investment, or closure decisions which do not reflect the economic impact on the investment cost of the transmission network which they cause. This would result in an outcome which is less economically efficient at a higher cost to society and ultimately a higher cost to customers.

3. Thirdly, there is a locational security of supply risk. The current defect provides the perverse economic price signal that as more intermittent low carbon plant is built in a zone, then low load factor peaking plant experience higher TNUoS charges. This is a self reinforcing “death spiral” for low load factor peaking plant because as the charges

increase and low load factor peaking plant are encouraged to close, then this would further reduce the assumed degree of sharing, which would feed back to further increase the price signal for remaining low load factor peaking plant to close. If left uncorrected, then for that zone, the "death spiral" would result in a shortage of low load factor peaking plant and an increasing reliance on imported power to meet peak demand, which would result in an increasing risk to security of supply for customers in that zone.

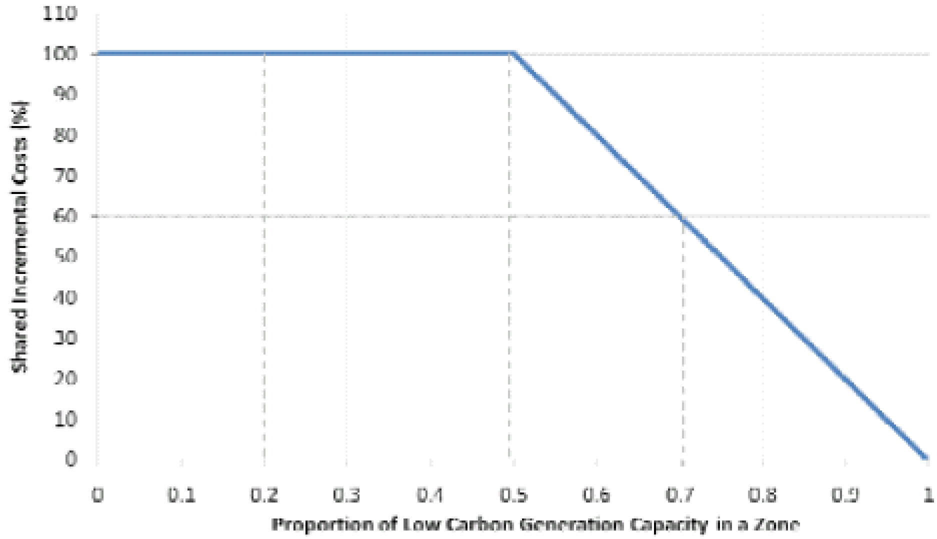
Description of the CUSC Modification Proposal

The proposal is that the charging methodology should be changed to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator's ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements. This does not change the way the Year Round tariff is calculated and it does not change existing generator classifications, but it does change the formula by which the Year Round tariff is applied to different types of Conventional generator. This is described in more detail below.

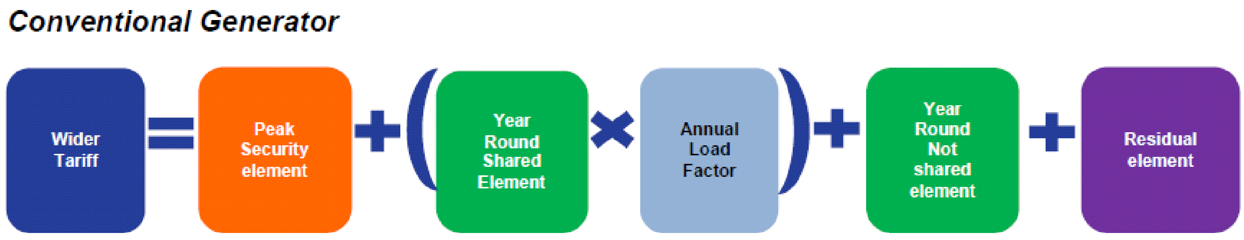
The element of the current tariff formula to be changed

In ICRP Transport model, the cost of Year Round circuits is allocated between Shared and Not Shared according to the relative share of "Low Carbon" compared with "Carbon" plant. The methodology assumes 100% sharing of circuits where the proportion of load flow of "Carbon" is between 100% and 50%. Beyond this point methodology assumes a straight line reduction in the degree of sharing from 50% until the proportion of load flow on the circuit accounted for "Carbon" plant declines to 0%. This is illustrated in the graph below.

Figure 18 from the CMP213 Workgroup report.

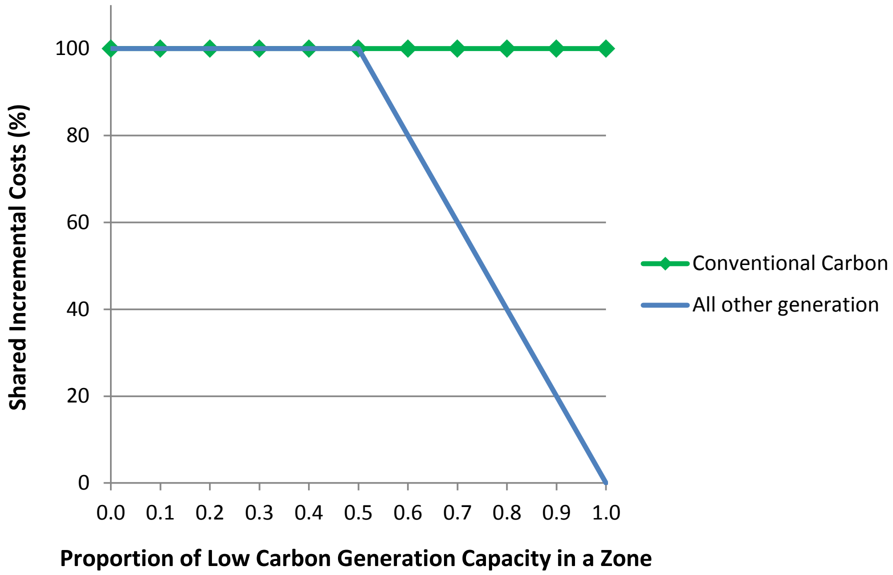


This principle is enacted through the current formula within the charging methodology where all generators (including Conventional Carbon generators) have their ALF applied to their Shared Year Round tariff element, but their ALF is not applied to their Not Shared Year Round tariff element. This is illustrated for Conventional Generators by the formula below taken from National Grid published Final TNUoS tariffs for 2016/17.



Proposed change to TNUoS tariff formula

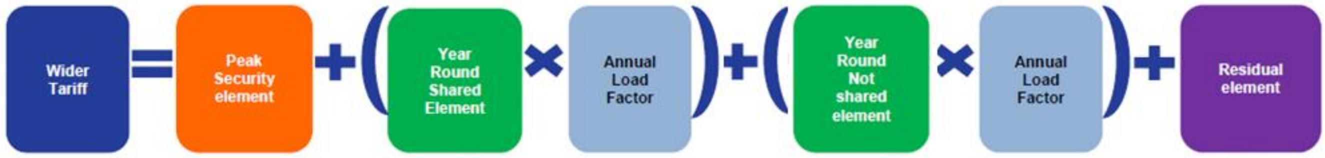
This modification proposes a change to the tariff formula relating to the way sharing is applied to Conventional Carbon generators so they continue to obtain 100% sharing of incremental costs irrespective of the proportion of low carbon generation capacity in a zone. This is illustrated by the graph below, which is a modified version of "figure 18" above.



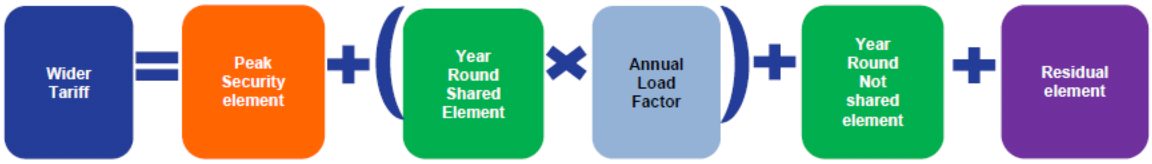
This modification proposal will recognise that even when the proportion of "Low Carbon" plant influencing a boundary is close to 100%, then any conventional carbon plant should have its ALF applied to the whole Year Round tariff (both Shared and Not-Shared elements of Year-Round).

This will require the existing tariff formula relating to "Conventional Generator" to be changed by splitting it into two parts: firstly "Conventional Generator – Carbon" and secondly "Conventional Generator - Low Carbon". For the avoidance of doubt, the existing tariff formula relating to "Intermittent Generator" is unchanged by this modification proposal. The proposed new tariff calculation formulas are illustrated below:

1) Adjusted tariff formula: "Conventional Generator – Carbon"
This represents a change from the existing "Conventional Generator" tariff formula since it applies the Generator's ALF to both its Not Shared Year Round as well as its Shared Year Round tariff elements.



2) Unchanged tariff formula: "Conventional Generator – Low carbon"
The tariff calculation remains the same as the current "Conventional Generator" tariff. It would be appropriate to give this unchanged tariff formula a new name to ensure it is clear which types of generation this applies to.



It is proposed that this new tariff calculation methodology would apply from the TNUoS charging year starting April 2017.

Impact on the CUSC

CUSC Section 14 – Part 2 – The Statement of the Use of System Charging Methodology, Section 1 – The Statement of the Transmission Use of System Charging Methodology

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

No

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

BSC ☐

Grid Code ☐

STC ☐

Other ☐

(please specify) *This is an optional section. You should select any Codes or state Industry Documents which may be affected by this Proposal and, where possible, how they will be affected.*
Urgency Recommended: Yes / No
Yes.
Justification for Urgency Recommendation
This proposal should be treated as urgent as it is linked to an imminent date related issue; namely that bids to the capacity mechanism auction for 2017/18 and for 2020/21 could be significantly impacted. If the defect is not urgently addressed there may be a significant commercial impact on generator parties.
Self-Governance Recommended: Yes / No
No
Justification for Self-Governance Recommendation
Should this CUSC Modification Proposal be considered exempt from any ongoing Significant Code Reviews?
Yes
Impact on Computer Systems and Processes used by CUSC Parties:
Details of any Related Modification to Other Industry Codes
Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:
Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.

Use of System Charging Methodology

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

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

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

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

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

Full justification:

In respect of (a) this modification will better facilitate effective competition in the supply of electricity because it will result in a more level playing field by correcting an existing TNUoS tariff defect which provides a non cost reflective economic disadvantage for a particular group of generators i.e. Conventional Carbon generators in a zone with a high share of low carbon generation.

In respect of (b) this modification will improve the cost reflectivity of Generation TNUoS charges.

Additional details

Details of Proposer: (Organisation Name)	SSE plc

Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	John Tindal SSE plc 01738 457308 John.tindal@sse.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Garth Graham SSE plc 01738 456000 garth.graham@sse.com
Attachments (Yes/No): **If Yes, Title and No. of pages of each Attachment:**	

Contact Us

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

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

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

Submitting the Proposal

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

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

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

Annex 2 – CMP268 Terms of Reference

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Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP268 WORKSHOP

CMP268 aims to change the charging methodology to more appropriately recognise that the different types of “Conventional” generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of “Conventional” generation pays. The change to the charging methodology would take the form that for generators which are classed as Conventional Carbon, the generator’s ALF should be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements. This does not change the way the Year Round tariff is calculated and it does not change existing generator classifications, but it does change the formula by which the Year Round tariff is applied to different types of Conventional generator.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP268 ‘Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits’** was tabled by **SSE** at the CUSC Modifications Panel meeting on 29 July 2016.

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

Use of System Charging Methodology

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

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

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

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

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

(e)Promoting efficiency in the implementation and administration of the CUSC arrangements.

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

Scope of work

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

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

   a. Reviewing CMP213
   b. Distribution impacts
   c. HVDC implications and links

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

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

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

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

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

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

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

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **14 October 2016** for circulation to Panel Members. The final report conclusions will be presented to the Special CUSC Modifications Panel meeting on **18 October 2016**.

Membership

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

Role	Name	Representing
Chairman	Ryan Place	National Grid
National Grid Representative*	Damian Clough	National Grid
Industry Representatives*	John Tindal (Proposer)	SSE PLC
	James Anderson	Scottish Power
	Bill Reed	RWE
	Paul Jones	Uniper
	Paul Mott	EDF Energy
Authority Representatives	Andrew Malley	Ofgem
Technical secretary	Chrissie Brown	National Grid
Observers		

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

14. The chairman of the Workgroup and the Modifications Panel Chairman must agree a number that will be quorum for each Workgroup meeting. The agreed figure for CMP268 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

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

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

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

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

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

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

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

Appendix 1 – Indicative Workgroup Timetable (Urgent) – Proposed Code Administrator Recommended Timetable

27 July 2016	CUSC Modification Proposal and request for Urgency submitted
29 July 2016	CUSC Panel meeting to consider proposal and urgency request
2 August 2016	Panel's view on urgency submitted to Ofgem for consultation
29 July 2016	Request for Workgroup members (5 Working days) (responses by 25 July 2016)
23 August 2016	Ofgem's view on urgency provided (15 Working days)
31 August 2016	Workgroup meeting 1
5 September 2016	Workgroup meeting 2
16 September 2016	Workgroup Consultation issued (10 days)
30 September 2016	Deadline for responses
12 October 2016	Workgroup meeting 3
14 October 2016	Workgroup report issued to CUSC Panel
18 October 2016	Special CUSC Panel meeting to approve WG Report

Post Workgroup modification process

20 October 2016	Code Administrator Consultation issued (10 Working days)
3 November 2016	Deadline for responses
7 November 2016	Draft FMR published for industry comment (3 Working Days)
10 November 2016	Deadline for Industry comments
7 November 2016	Draft FMR circulated to Panel
14 November 2016	Special CUSC Panel meeting for Panel recommendation vote
16 November 2016	FMR circulated for Panel comment (2 Working days)
18 November 2016	Deadline for Panel comment
22 November 2016	Final report sent to Authority for decision
1 December 2016	Indicative Authority Decision due (7 working days)
7 December 2016	Implementation date

Please note that the timetable is one week behind the timetable agreed by Ofgem and the CUSC Panel following urgency being granted.

Annex 3 – Workgroup attendance register

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

Name	Organisation	Role	31/08/2016	05/09/2016	08/09/2016	7/10/2016	12/10/2016
John Martin	National Grid	Chair	A	X	X	X	X
Ryan Place	National Grid	Chair	X	A	A	A	A
Heena Chauhan	National Grid	Technical Secretary	A	A	A	X	X
John Tindal	SSE	Proposer	A	A	A	A	X
Damian Clough	National Grid	Workgroup member	A	A	A	A	A
Bill Reed	RWE	Workgroup member	D	A	A	A	D
Paul Jones	Uniper	Workgroup member	A	X	A	A	D
Paul Mott	EDF Energy	Workgroup member	D	A	A	A	D
James Anderson	Scottish Power	Workgroup member	D	A	D	A	D
Andrew Malley	Ofgem	Authority Representative	D	D	D	A	X
Chrissie Brown	National Grid	Technical Secretary	X	X	X	A	A
Garth Graham	SSE	Workgroup member alternate	X	X	X	X	D

The Workgroup attendance register tracks the attendance of the Workgroup so that you can see how many people have attended when it comes to the Workgroup vote. In order to vote, Workgroup members need to have attended at least 50% of Workgroup meetings (either in person, teleconference or by sending an alternate) to be eligible to vote.

Annex 4 – Panel urgency letter

White House,
24 Upper West Street,
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Home: 01737 242960
Mobile Telephone Number: 07770 341581
e-mail: miketoms53@btinternet.com

Abid Sheikh
Industry Codes Manager
Ofgem
By email

2 August 2016

Dear Abid

CUSC Modifications Panel Views on Urgency for CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

On 26 July 2016, SSE raised CMP268, with a request for the proposal to be treated as an Urgent CUSC Modification Proposal. The CUSC Modifications Panel ("the Panel") considered CMP268 and the associated request for urgency at the CUSC Modifications Panel meeting held on 29 July 2016. This letter sets out the views of the Panel on the request for urgent treatment and the procedure and timetable that the Panel recommends.

CMP268 proposes to change the charging methodology to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays ideally ahead of the December Capacity Auction.

Request for Urgency
The Panel considered the request for urgency with reference to Ofgem's Guidance on Code Modification Urgency Criteria. The majority view of the Panel is that CMP268 does not meet these criteria and SHOULD NOT be treated as an Urgent CUSC Modification Proposal.

The Panel concluded that the Proposal did not relate to an imminent issue and although the proposal seeks to address an existing issue in the CUSC resulting from the implementation of CMP213, CMP268 will require careful consideration and is potentially more complex than envisaged by the Proposer and therefore not achievable within the timescales.

In the discussion, members of the Panel noted a few concerns over granting urgency, set out below;

- The Panel recognised analysis presented within the CMP213 Final Modification Report could be re-used by a Workgroup but agreed that this would need to be refreshed to bring it up to date.
- Using an urgent process holds an inherent risk of unintended consequences, which may arise due to there being insufficient time for all aspects of a Modification Proposal to be considered;
- There are complex issues identified by the Panel that need to be considered by a Workgroup.

Procedure and Timetable
Having decided to not recommend urgency to Ofgem, the Panel discussed an appropriate process for CMP268. The Panel agreed that the CMP268 proposal would require a Workgroup and careful consideration due to the potential implications against principles agreed during the implementation of CMP213.

The Panel agreed that CMP268 subject to Ofgem's decision on Urgency should follow the attached Code Administrators proposed timetable (Appendix 1). This was supported by majority view.

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

Yours sincerely

Michael Toms
CUSC Panel Chair

Appendix 1 – Indicative Workgroup Timetable (Standard)

The following urgent timetable is following is indicative for CMP268 as per the recommendation of the Code Administrator

27 July 2016	CUSC Modification Proposal and request for Urgency submitted
29 July 2016	CUSC Panel meeting to consider proposal and urgency request
2 August 2016	Panel's view on urgency submitted to Ofgem for consultation
2 August 2016	Request for Workgroup members (5 Working days) (responses by 9 August 2016)
9 August 2016	Ofgem's view on urgency provided (5 Working days)
w/c 8 September 2016	Workgroup meeting 1
w/c 3 October 2016	Workgroup meeting 2
w/c 24 October 2016	Workgroup meeting 3
9 November 2016	Workgroup Consultation issued (15 days)
30 November 2016	Deadline for responses
w/c 5 December 2016	Workgroup meeting 4
w/c 19 December 2016	Workgroup meeting 5 (agree WACMs and Vote)
19 January 2017	Workgroup report issued to CUSC Panel
27 January 2017	CUSC Panel meeting to approve WG Report

Post Workgroup modification process

1 February 2017	Code Administrator Consultation issued (15 Working days)
22 February 2017	Deadline for responses
1 March 2017	Draft FMR published for industry comment (5 Working Days)
8 March 2017	Deadline for comments
23 March 2017	Draft FMR circulated to Panel
31 March 2017	Panel meeting for Panel recommendation vote
5 April 2017	FMR circulated for Panel comment (5 Working day)
12 April 2017	Deadline for Panel comment
14 April 2017	Final report sent to Authority for decision
24 May 2017	Indicative Authority Decision due (25 working days)
30 May 2017	Implementation date

Annex 5 – Ofgem view on urgency

Making a positive difference
for energy consumers

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

Direct dial: 020 7901 1857
Email: andrew.self@ofgem.gov.uk

Date: 23 August 2016

Dear Mr Toms,

CMP268 '*Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'* – decision on urgency

On 26 July 2016, SSE (the 'Proposer') raised Connection and Use of System Code (CUSC) modification proposal CMP268. This proposal seeks to change the Transmission Network Use of System (TNUoS) Charging methodology set out in the CUSC which, in the Proposer's view, fails to reflect the fact that different types of conventional generation cause different transmission network investment costs. The Proposer requested that CMP268 be treated as an Urgent CUSC Modification Proposal.

The CUSC Modifications Panel (the 'Panel') considered the Proposer's urgency request at its meeting on 29 July 2016. On 2 August 2016, the Panel wrote to inform us of its majority view that CMP268 should not be treated as urgent because the proposal did not relate to an imminent issue, would require careful consideration and was potentially more complex than envisaged by the Proposer.

In addition to the Panel's letter, we received information from the Proposer which is commercially sensitive and confidential, and was therefore not submitted to the Panel.

We considered both the Panel's and the Proposer's arguments. On balance, we have decided that CMP268 **should be progressed on an urgent basis**. We have set out our reasoning below.

The proposal

The Proposer considers that the current charging methodology fails to reflect the fact that different types of conventional generation, eg CCGTs[1] compared to nuclear, cause different transmission network investment costs to be incurred due to their different network sharing characteristics. In particular, it considers that the sharing factor in the Year Round tariff does not adequately reflect how conventional carbon generators drive costs in zones where low carbon generation penetration is greater than 50%.

[1] Combined Cycle Gas Turbine power stations

The Proposer therefore thinks that the current charging methodology is not cost-reflective for those plants. CMP268 would change the application of the sharing factor for conventional carbon generators to deal with this perceived defect.

The Proposer also claims that CMP268 should be treated as an urgent modification because the defect materially inhibits certain generators' ability to participate in the bids to the Capacity Market (CM) auction for 2017/18, which will take place in December this year, and for the 2020/21 CM auction. It argues that, as a result, if the defect is not urgently addressed, certain generators would be significantly commercially affected.[2]

Panel discussion

The Panel considered the request for urgency by reference to Ofgem's Guidance on Code Modification Urgency Criteria. The Panel's majority view is that CMP268 did not meet these criteria and should not be treated as an Urgent CUSC Modification Proposal.

The Panel concluded that the proposal did not relate to an imminent issue. While it sought to address an existing issue in the CUSC resulting from the implementation of CMP213[3], CMP268 requires careful consideration and is potentially more complex than envisaged by the Proposer. Full assessment of the proposal is therefore not achievable within urgent timescales.

Panel members had concerns about granting urgency. These were about refreshing any re-use of analysis presented within the CMP213 Final Modification Report, the inherent risk of unintended consequences with an urgent process, and concern that any workgroup assessing CMP268 would need to consider complex issues identified by the Panel.

Our views

We have considered the proposal, the Panel's views and the Proposer's arguments for urgency, and additional, commercially sensitive, information sent to us on a confidential basis.

We have assessed the request against the urgency criteria set out in our published guidance[4], in particular, whether the proposal is linked to an imminent issue or a current issue that, if not urgently addressed, may cause:

a. a significant commercial impact on parties, consumers or other stakeholder(s); or
b. a significant impact on the safety and security of the electricity and/or gas system.

We accept the Proposer's case and have decided that CMP268 should be granted urgent status because of the potential significant commercial impact on some power plants linked to the timing of the next two CM auctions in December 2016 and January 2017.

The Proposer argues that the current arrangements also result in a significant impact on safety and security. We do not accept this argument. We consider that the CM is designed to procure the amount of capacity needed to meet the reliability standard.

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[2] The Proposer's reasoning is set out in the CMP268 Proposal form at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/.
[3] Our decision on CMP213 is available here: https://www.ofgem.gov.uk/publications-and-updates/project-transmit-decision-proposals-change-electricity-transmission-charging-methodology . CMP213 was implemented on 1 April 2016.
[4] https://www.ofgem.gov.uk/system/files/docs/2016/02/urgency_criteria.pdf

We note the Panel's concerns on the complexity of the proposal and the careful consideration needed, but we do not consider that these in themselves are reasons for rejecting urgency. We would however emphasise that, as for all proposals, we expect a sufficient level of analysis and stakeholder engagement to be undertaken in order to demonstrate whether or not CMP268 facilitates the Relevant Objectives better and is consistent with our principal objective and statutory duties.

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

Next steps

The Panel's letter contained only a non-urgent indicative timetable for progressing CMP268. The Panel should now present a new urgent timetable for our approval which takes account of the Proposer's need for a timely decision but also allows for sufficient industry consultation and analysis, and for us to have sufficient time to reach a reasoned decision. This new timetable should be submitted to us no later than 26 August 2016.

CMP268 could have been raised sooner, given that, on 1 March 2016, the Government announced its proposal to bring forward the start of the CM delivery period by a year to 2017/18. We expect proposers who are seeking urgent status for CUSC Modification Proposals to raise their modifications more promptly and will take any delay into account when considering, under our Urgency Criteria, whether the matter is truly urgent.

Yours sincerely,

Andrew Burgess
Associate Partner, Energy Systems
Duly authorised on behalf of the Authority

Annex 6 – Panel recommended timetable following Authority urgency decision

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

Abid Sheikh
Industry Codes Manager
Ofgem
By email

26 August 2016

Dear Abid

CUSC Modifications Panel Recommended Timetable for CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

On 26 July 2016, SSE raised CMP268, with a request for the proposal to be treated as an Urgent CUSC Modification Proposal. The CUSC Modifications Panel ("the Panel") considered CMP268 and the associated request for urgency at the CUSC Modifications Panel meeting held on 29 July 2016. This letter sets out the views of the Panel on the request for urgent treatment and the procedure and timetable that the Panel recommends.

CMP268 proposes to change the charging methodology to more appropriately recognise that the different types of "Conventional" generation do cause different transmission network investment costs, which should be reflected in the TNUoS charges that the different types of "Conventional" generation pays ideally ahead of the December Capacity Auction.

Request for Urgency
The Panel wrote to the Authority on 2 August 2016 which considered the request for urgency with reference to Ofgem's Guidance on Code Modification Urgency Criteria. The majority view of the Panel was that CMP268 did not meet these criteria and SHOULD NOT be treated as an Urgent CUSC Modification Proposal.

The Authority has since considered the views of the Panel along with confidential information received from the Proposer which had not been submitted to the Panel.

The Authority wrote to the Panel on 23 August 2016 and on balance has accepted the Proposer's case and has decided that CMP268 SHOULD BE granted urgent status because of the potential significant commercial impact on some power plants linked to the timing of the next two CM auctions in December 2016 and January 2017.

The Authority note the Panel's concerns on the complexity of the proposal and note that careful consideration is needed, but do not consider that these in themselves are reasons for rejecting urgency. They do however emphasise that, as for all proposals, a sufficient level of analysis and stakeholder engagement is expected to be undertaken in order to demonstrate whether or not CMP268 facilitates the Relevant Objectives better and is consistent with their principal objective and statutory duties.

The Panel's original letter contained only a non-urgent indicative timetable for progressing CMP268. At the Authority's request, the Panel is now presenting a new urgent timetable for your approval which takes account of the Proposer's need for a timely decision but also allows for sufficient industry consultation and analysis, and for sufficient time to reach a reasoned decision.

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

Yours sincerely

Michael Toms
CUSC Panel Chair

Appendix 1 – Recommended Urgent Workgroup Timetable

The following urgent timetable is following is indicative for CMP268 as per the recommendation of the Code Administrator and the CUSC Panel

27 July 2016	CUSC Modification Proposal and request for Urgency submitted
29 July 2016	CUSC Panel meeting to consider proposal and urgency request
2 August 2016	Panel's view on urgency submitted to Ofgem for consultation
29 July 2016	Request for Workgroup members (5 Working days) (responses by 25 July 2016)
23 August 2016	Ofgem's view on urgency provided (15 Working days)
31 August 2016	Workgroup meeting 1
5 September 2016	Workgroup meeting 2
9 September 2016	Workgroup Consultation issued (10 days)
23 September 2016	Deadline for responses
28 September 2016	Workgroup meeting 3
3 October 2016	Workgroup meeting 4 (agree WACMs and Vote)
7 October 2016	Workgroup report issued to CUSC Panel
11 October 2016	Special CUSC Panel meeting to approve WG Report

Post Workgroup modification process

13 October 2016	Code Administrator Consultation issued (10 Working days)
27 October 2016	Deadline for responses
1 November 2016	Draft FMR published for industry comment (3 Working Days)
4 November 2016	Deadline for Industry comments
1 November 2016	Draft FMR circulated to Panel
8 November 2016	Special CUSC Panel meeting for Panel recommendation vote
10 November 2016	FMR circulated for Panel comment (2 Working day)
14 November 2016	Deadline for Panel comment
16 November 2016	Final report sent to Authority for decision
25 November 2016	Indicative Authority Decision due (7 working days)
30 November 2016	Implementation date

Annex 7 – Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

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 **30 September 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Chrissie Brown at Christine.brown1@nationalgrid.com

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

Respondent:	*Joe Underwood – Joseph.Underwood@drax.com*
Company Name:	*Drax Power Limited*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	*CMP268 will adversely affect the Applicable CUSC Objectives (a), (b) and (c). Please see our answers to the questions below for reasoning.*

Standard Workgroup consultation questions

Q	Question	Response

1	**Do you believe that CMP268 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	No. Due to such a short timescale we do not believe that the workgroup has had sufficient time to properly assess the proposal. The current methodology approved under CMP213 WACM2 is a relatively simplistic and transparent one but to improve its accuracy will require a much more complex solution as was recognised in the Ofgem CMP213 decision letter. This could result in the methodology becoming less transparent, less forecastable and could represent a barrier for entry. Therefore any changes to the TNUoS charging methodology should not be small "quick fixes" that only identify narrow sections of the equation, but be in the form of a more in-depth, fundamental review that looks at all the elements of the wider tariff. To properly assess the benefit of change to the current methodology, new, comprehensive analysis would need to be undertaken. In particular, the flows on the system need to be properly assessed, not just at peak times but also in times when large numbers of actions are taken by the SO such as the Summer overnight periods. These actions historically have not been prevalent but the generation landscape has developed and flows on the system are now proving problematic for the SO to deal with. We do have some sympathy with the defect that the Proposer has raised. There is an increasing need for flexible plant to provide ancillary services in order to ensure the efficient management of the system throughout GB. However, the TNUoS charging arrangements may not provide efficient signals for siting flexible plant in the North and particularly Scotland. A change to the charging arrangements should be considered to rectify this probable defect, however, CMP268 is probably not the answer and the issue should be addressed by a wider charging review. We believe that it cannot be demonstrated that CMP268 improves cost reflectivity of the transmission charging methodology and possibly only acts to redistribute costs between generators. As such, there is a risk that CMP268 will distort competition and will cause inefficiently located plant to stay open longer, and more efficiently located plant to close sooner thereby going against the intention of CMP213. It should also be noted that plant located in areas with a slightly positive Not-Shared tariff, who should benefit from this modification, will in fact be adversely impacted relative to non-GB transmission connected generation by CMP268 due to the estimated £0.17/kW increase in the generator residual.

Q	Question	Response
		In summary, we believe that CMP268 will adversely affect the Applicable USC Objectives (a), (b) and (c).
2	**Do you support the proposed implementation approach?**	No, the modification has been conducted under urgent timescales and therefore a proper assessment of whether CMP268 improves cost reflectivity has not been done.
3	**Do you have any other comments?**	Table 1 on page 37 of the workgroup report titled *2017/18 Impacts on Parties Costs* could be considered misleading. The final column does not show the true impact on each party as the effect of the increasing residual as a result of CMP268 has not been included. It results in the report being misleading and could open the Authority decision up to review if not remedied. This may disguise the fact that parties, in particular smaller parties, who may not have run the numbers themselves see a different impact if CMP268 were to be approved than would otherwise be the case.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	Not at this time.

CUSC Workgroup Consultation Response Proforma

CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

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 **30 September 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Chrissie Brown at Christine.brown1@nationalgrid.com

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

Respondent:	Paul Mott
Company Name:	EDF Energy
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission

	businesses; (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.). *Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

Standard Workgroup consultation questions

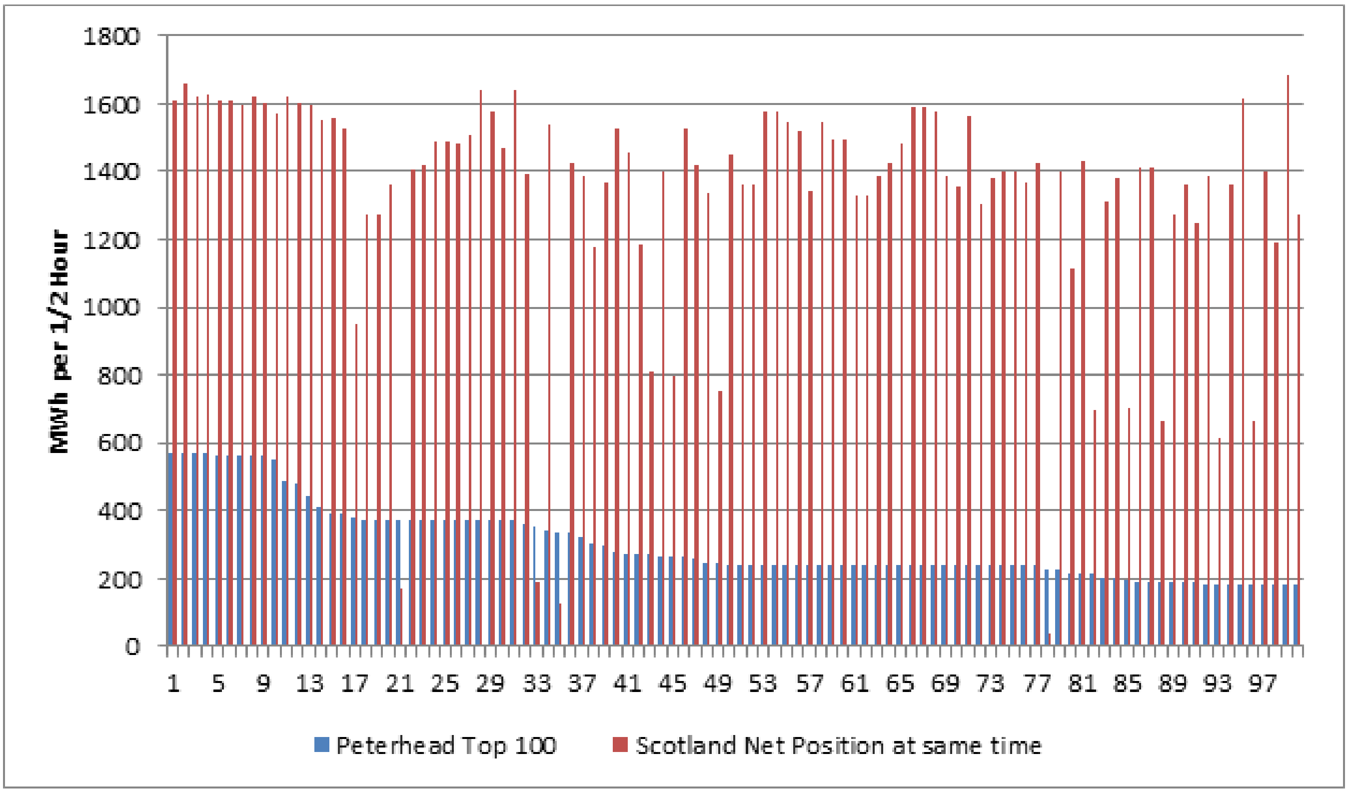
Q	Question	Response
1	**Do you believe that CMP268 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	In the Proposer's view the defect is that there is a specific circumstance where the charging methodology is not cost reflective because it fails to recognise that Conventional Carbon plant does in fact continue to fully share all Year-Round circuit costs even in circumstances when the proportion of plant which is Low Carbon exceeds 50%. This is said to be because Conventional Carbon generators tend to provide positive bid prices, so continue to provide a relatively low cost option for managing constraints irrespective of the concentration of low carbon generation behind a boundary, assuming that which plant runs is determined by regional energy balancing, and not by other system requirements. The Proposer contends that the ability of Conventional Carbon generators to share with Low Carbon plant actually increases as Low Carbon plant becomes more dominant. **<u>Our View:</u>** **Summary** We do not believe that CMP268 better facilitates the applicable CUSC objectives. 1. We do not believe the proposal can be approved. There is too little time available for an evidence-based decision to be made on re-opening CMP213, bearing in mind the depth of expertise and duration of study that was brought to bear on the review of transmission charging during Project TransmiT. 2. We know that the 'defect' asserted by the proposer was explicitly considered in CMP213 and a balanced decision was made to adopt the current diversity method. We believe that re-opening a single issue within the overall framework of the diversity method is unjustified. 3. We have anyway strong doubts about the cost-reflectivity of the proposal, which asserts benefits arise from 'sharing' transmission in wind-dominated zones, based on our evidence of both Scottish pumped storage and Scottish gas-fired generation running more during times of high Scottish wind output than low. **Process:** The timescale for consideration of the modification proposal, and the way it has overlapped with other significant charging changes which draw on much of the same pool of industry expertise, has prevented a thorough debate and it was not possible at the workgroup to debate or evaluate well the existing evidence or carry out new analysis. A thorough, evidence-based final decision process on this modification proposal is very unlikely to be possible without additional evidence either collected by use of "send back", or via an impact assessment. The identification of appropriate treatments of diversity in the CMP213 workgroup, alongside and as part of identification suitable means of applying the resulting new tariff elements, took months. The CMP268 workgroup process has by contrast been extremely rushed, the first meeting taking place in an early evening after another workgroup meeting that day, by teleconference with a dispersed membership, and one of the workgroup meetings on Monday 12th September taking place between 09:00 and 10:00 only, in the morning.

Q	Question	Response
	Question 1 continued	*Continuation to reply to question 1 (or text becomes invisible and unprintable)* We have never known a material modification proposal to be processed in such a hasty manner. It is unlikely that any respondent to this consultation will have time to commission any new analysis of their own, particularly at such a peak in the CUSC modifications workload, with 29 “live” CUSC mods, some being of much significance. **Previous Assessment:** We note that in paragraph 1.15 of its decision letter on CMP213, Ofgem wrote : “*The Year Round tariff would be further adjusted into a ‘shared’ and ‘non-shared’ element. The split is based on the proportion of low carbon generation in an area. If the level of low carbon plant behind a boundary is 50% or less, then the entire Year Round tariff is shared. Once this percentage exceeds 50%, an increasing proportion is considered ‘non-shared’. This change is to reflect that plant in zones dominated by low carbon plant tend to drive higher levels of constraint costs and therefore investment than if there is a range of plant in a zone.*” This recognises that more generation plant in an export-constrained zone tends to drive higher levels of constraint costs, particularly as the proportion of lower carbon plant increases above 50%. Graphs of plants bid prices and estimated BSUoS arising from constraints were presented to the CMP213 workgroup by National Grid; there has been no time at the CMP268 workgroup to re-examine this material which helped inform the painstaking identification at the CMP213 workgroup of options for treatment of diversity in the calculation and application of the new tariffs, and ultimately the selection of how to calculate and apply “Diversity Method 1” tariffs. CMP268 seeks to re-open this matter without sufficient time for proper analysis, discussion and consideration. Indeed it was stated as our terms of reference that National Grid would not commission any new or refreshed analysis. Ofgem’s decision on CMP213, also said of the chosen approach, diversity method 1, “…. *it will not precisely reflect the impact a generator has on transmission investment in every circumstance, especially at the extremes, for example, when there is 0% or 100% of a particular type of generator in a zone. A more accurate calculation that captured all the factors that affect investment decision-making would require considerably more complexity...We think this would make the charging methodology less transparent and more difficult to forecast. We consider that this would be a barrier to entry, reduce competition and would offset any gains from the additional precision. It will never be possible to exactly capture the impact of an individual generator on the system while remaining within the principles of the ICRP methodology. Balancing accuracy with the simplicity and transparency of tariffs is an important part of the ICRP methodology because of the impact these factors have on competition.”*

Q	Question	Response
	Question 1 continued	*Continuation to reply to question 1 (or text becomes invisible and unprintable)* A replacement of the calculation and application of tariffs under diversity method 1, would need new analysis to be undertaken and changes would need to be made to the calculation and application of tariffs. It would not be sufficient to make a simple change to the tariff APPLICATION as proposed under CMP268, as this would simply provide a competitive advantage to a minority of generators without improving cost-reflectivity. The development of diversity method 1 was influenced by considering the extent of Grid's ability under different scenarios to access lower cost bids. The likelihood of being able to access lower cost bids is increased if there is more lower cost generation in the zone, and diversity method 1 reflects this, by increasing the amount of shared circuits (increasing the shared tariff element) as the amount of diversity increases. The proposer has stated a concern that CMP213 gives rise to a signal for lower cost bid plant (carbon plant) to close in export-constrained areas. We believe that it gives a slightly better signal for more of such plant to locate in the area, as the result of this is to increase the amount of sharing in the price signal. A potential extra low-bid, carbon type, generator there would not make an investment decision based on the current price signal, as the proposer seems to assume, but on what it believed the signal would be after decision, which is slightly improved by making said decision. Albeit that locating behind a strongly export-constrained boundary is not ideal from the transmission system planner's point of view, for any new generation plant. **Our assessment:** We do not believe that the proposer's contention takes account of the difficulties that Grid has when there is a lot of low carbon plant of the asynchronous variety, running. Much of the low carbon plant of the asynchronous variety, of wind technology type, tends to be located behind the "B6" export-constraint boundary. Our analysis provided to the workgroup notes that in the windiest 10% of hours (Decile 10, the right-most bar in Figure 4 of the report), that the output from the Scottish pumped storage stations (green) and Peterhead (blue) are both significantly higher than in the least windy 10% of hours, indeed higher than in any other decile in-between. The reason is likely to be that when there is high wind output in such areas (and thus to a degree nationally), National Grid is presented with a number of System Operability issues. For instance the lack of "inertia" from wind may mean that National Grid takes steps to ensure that more of the carbon type plant is running nationally, including in these areas. Another reason why National Grid may require output from the carbon plant in these areas, even at times of high low carbon generation there, is for reasons of voltage or stability support, due to their good characteristics from a System Operator point of view, unrelated to local energy balance or thermal circuit limits.

Q	Question	Response
	Question 1 continued	*Continuation to reply to question 1 (or text becomes invisible and unprintable)* The proposer contested the analysis on the basis that: 1) Pumped storage plant is able to pump at times of high demand, and will be providing synchronous inertia at such times, and 2) In comparing low carbon output net of demand, they discarded the Peterhead output data. The graph at the base of this response, outside this tabular format, has a plot of Peterhead's output (blue), stacked from the highest Peterhead output on the left of the X axis to the lowest Peterhead output on the right, the red lines representing total Scottish low carbon generation net of Scottish demand. Looking towards the left of this chart, there is an apparent correlation between times of high Scottish low carbon generation net of Scottish demand, and high output from Peterhead, supporting a thesis that Peterhead may be required by Grid for system reasons at such times. We believe that it has not been proven that CMP268 improves the cost reflectivity of the transmission charging methodology. There is a resultant risk of providing an unfair competitive advantage, including in the Capacity Market, to a subset of generators through a redistribution of TNUoS costs. The impact numbers that National Grid published to workgroup members, showed that this advantage could be considerable, at up to £6m p.a. per plant. We do not agree that the proposer's contention, that there is a defect, holds in principle not least because of the system operability issues highlighted. The limited evidence presented also does not appear to support there being a defect either.
2	**Do you support the proposed implementation approach?**	We do not believe that this modification should be implemented; if it were, at least two years' notice is needed before implementation of such a material change. Implementation from April 2017 is certainly not appropriate.
3	**Do you have any other comments?**	No, we have made them all above

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*No*



CUSC Workgroup Consultation Response Proforma

CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

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 **30 September 2016** to cusc.team@nationalgrid.com Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Workgroup.

Any queries on the content of the consultation should be addressed to Chrissie Brown at Christine.brown1@nationalgrid.com

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

Respondent:	*Paul Jones paul.jones@uniper.energy*
Company Name:	*Uniper*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission

	businesses; (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.). *Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP268 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	No. We have detailed reasons which would not conveniently fit into this form and we have attached them on a separate sheet.
2	**Do you support the proposed implementation approach?**	No.
3	**Do you have any other comments?**	No thank you.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No thank you, as we do not believe that there is a defect to address.

Q1. Do you believe that CMP268 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?

No we do not. This modification would act against charging objectives a) and b).

The problem with CMP268 is that it is based on a misunderstanding about the basis for the present charging methodology. To understand how the current Shared and Not Shared charges came about, it is necessary to review the history of how CMP213 came to establish these charges.

1. **The CMP213 methodology change was based on introducing the principles established through a change to the System and Quality of Supply Standards (SQSS) called GSR009.**

GSR009 introduced into the SQSS two sets of criteria for assessing the network investment required to connect onshore generation. Ofgem's decision letter to approve GSR009 is helpful in explaining this:

"*GSR009 proposes a 'dual criteria' approach to assessing required capacity which would take into account both demand security and economic efficiency when developing the transmission network. Each of these criteria would include specific assumptions about different types of generation, including intermittent generation. A more detailed description of the proposals has been attached to this letter as Appendix 1, but in summary the proposals would introduce:*

- *A Demand Security Criterion which requires sufficient transmission system capacity such that peak demand can be met without intermittent generation (thus ensuring demand security at times when weather or other conditions prevent intermittent generation).*

- *An Economy Criterion which requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The approach involves a set of deterministic parameters which have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between the constraint costs and the costs of transmission reinforcements. The assumptions in the generic or pseudo CBA would be reviewed every five years.*

The more onerous of these two criteria would be binding (ie that which indicates the higher capacity requirement)."

So essentially under GSR009, when planning the system to accommodate new generation, the SO will assess whether infrastructure is needed to meet peak demand (without any running assumed from intermittent generation) and also undertake a "pseudo cost benefit analysis" of whether it is better to invest rather than incur more constraints year round.

The more onerous of the two requirements will be invested against.

2. **Circuits in the transport model used to set TNUoS tariffs would be allocated to different charge "pots" to reflect the SQSS criteria**

National Grid uses a transport model as the basis of calculating its locational TNUoS charges. The model assesses how much investment will be needed to accommodate an additional MW of generation, or demand, at different parts of the network. The model essentially estimates the circuits that a generator is likely to be using due to its location, as well as the extent to which those circuits are used, and seeks to allocate a share of the cost of those circuits to the generator.

Previous to the introduction of CMP213 the individual costs of each circuit would be added up to form the locational part of the tariff (expressed in £/kW). CMP213 changed this by allocating different circuits to different "pots" dependent on whether they were more likely to be upgraded under the SQSS GSR009 under the Demand Security Criterion or the Economy Criterion. The Demand Security Criterion circuit costs are allocated to the System Peak charge "pot" and the Economy Criterion costs are allocated to the Year Round charge "pot".

The basic principle established under CMP213 was that the System Peak costs would not be allocated to intermittent generation, to reflect that these plant do not figure in the Demand Security assessment, whereas the Year Round costs would be allocated to all generation.

3. Year Round charges to be scaled by an Annual Load Factor (ALF)

As the Year Round Charge was based on the principle that constraint costs incurred by connecting generation in a particular location would drive the level of network investment, National Grid as proposer believed that the charge should be scaled to reflect the amount of constraints a generator was likely to cause. National Grid proposed that there was a relationship between a station's load factor and the amount of constraints that were caused on the system and set out to use modelling to assess the extent to which this was the case.

The modelling did sometimes show a relationship to some extent, but this didn't always hold true. Further assessment of why this was the case concluded that in areas dominated by intermittent low carbon generation, such as wind, the System Operator (SO) was less likely to be able to access bids from carbon plant which were closer to market value in order to manage constraints. Instead, it was concluded that the SO would have to constrain off the more expensive low carbon plant. In these circumstances it was deemed that the decision would be made to build network instead of incurring constraint costs.

For instance, this was reflected in paragraph 4.36 of the CMP213 Workgroup Report which stated:

"*It was further postulated by the modelling subgroup that the ideal network scenario is to build transmission network such that the low carbon plant is rarely constrained off, and a network of this size could absorb an equal volume of carbon plant. In such an idealised transmission network, constraint action would only be required on carbon plant and this can be accessed at relatively low cost. In any event, for significantly expensive actions (negative bid price) the general assumption is that, in areas where this type of plant is dominant, TOs would build transmission network capacity at or very close to the total generation capacity in the area concerned. Likewise, where the costs of constraining plant off was [sic] relatively low, the general assumption is that the transmission network capacity would not be very close to the total generation capacity in the area concerned and this would, therefore, mean lower transmission network investment.*"

4. Year round charges to be split into Shared and Not Shared

In light of this breakdown in the relationship between load factor and constraint costs, it was proposed that the Year Round charge should be split into two constituent elements. Essentially, for zones where low carbon generation made up 50% or less of the generation then year round circuits would be allocated to a "Shared" charge element. When low carbon generation made up a greater proportion than this, then some of the circuit cost would be allocated to a "Not Shared" element.

The Shared Year Round charge would be scaled by the generator's ALF. However, the Not Shared charge would not, to reflect the fact that the SO would choose to invest in network rather than incur constraints. The charge was simply devised to reflect diversity in the zone. It didn't attempt to reflect the impact that different bid prices had on constraint costs for instance. This was specifically referenced in 4.137 of the CMP213 workgroup report which said:

"*Whilst annual load factor is generation plant specific, the diversity element is related to the zonal availability of sufficient non low carbon plant (or simply – Carbon plant) in a TNUoS zone (i.e. plant with a near marginal bid price). As the Workgroup were minded not to look for a complex solution based on bid price, Method 1 would utilise the ratio of cumulative low carbon (LC) to carbon (C) generation TEC behind a zonal transmission boundary as set out in paragraph 4.130 to establish what proportion of the associated incremental kilometres making up the transmission boundary length were shared or not shared.*"

The wording here is notable in that it clearly states that the diversity element is related to the availability of "sufficient non low carbon plant". The implication is that if there is insufficient non low carbon plant the cost goes up. Therefore, diversity can be driven as much by have too little carbon plant in a zone as it can by having too much low carbon plant in a zone.

A more complex solution might have been available to the working group which reflected a generator's bid price as the extract above shows. However, the workgroup deemed that the diversity option should be chosen as it was simpler. This position was recognised by Ofgem too in paragraph 2.17 of its decision letter on CMP213

"*We therefore consider that WACM 2 is an improvement on the existing charging methodology. It represents a simple, transparent proxy for the impact of a generator on constraint costs, and therefore on transmission investment, taking into account the mix of generation in an area. However, it will not precisely reflect the impact a generator has on transmission investment in every circumstance, especially at the extremes, for example, when there is 0% or 100% of a particular type of generator in a zone. A more accurate calculation that captured all the factors that affect investment decision-making would require considerably more complexity. We think this would make the charging methodology less transparent and more difficult to forecast. We consider that this would be a barrier to entry, reduce competition and would offset any gains from the additional precision. It will never be possible to exactly capture the impact of an individual generator on the system while remaining within the principles of the ICRP methodology. Balancing accuracy with the simplicity and transparency of tariffs is an important part of the ICRP methodology because of the impact these factors have on competition.*"

Assessment of CMP268

We believe that the incentives provided by the current charging mechanism are correct. The proposer contends that the present methodology is acting as a closure signal to conventional plant and that this would have the effect of decreasing diversity. We assume that this comment specifically relates to Peterhead power station, although we cannot be certain as the additional information provided by the proposer to Ofgem to make the case for urgent assessment of the modification was kept confidential. However, we suspect that the proposer is confusing the signals provided by the diversity element of the methodology with the costs associated with being located at an expensive part of the network.

The signals provided by the diversity element are correct. As more carbon plant connects in a zone dominated by low carbon plant, the diversity of the zone increases and the charges adjust accordingly. Similarly, as the amount of low carbon generation decreases then the diversity decreases and the charges reflect that.

Generators do not make investment decisions assuming the present level of charge in a zone will always persist. By building capacity in a zone, the generator affects the level of charge for the zone. Therefore, it is the level of the charge after it invests which is important. So if a generator invests in a carbon generator in zone to increase diversity, then it will look at the charge it sees after it has invested. If it increases the diversity, the charge should go down and that gives the correct signal.

Of course the generator may well make a closure decision in reaction a current level of charge. In general, transmission charges tend not to be the determining factor on their own and are only likely to make much of a difference once a plant is struggling economically due to other issues, such as a lack of efficiency and/or reliability. However, as we mention above, as the diversity element of the methodology clearly gives the correct signal and moves in the correct manner as diversity changes, it is most likely that, if transmission charges are really the difference between a plant staying open and closing, it is its location in an expensive part of the network which is the issue.

Should CMP268 be implemented, it would result in a non cost reflective charge as it seeks to make a change which does not reflect the logic of why the Shared and Not Shared tariffs were put into place. The proposer suggests that the low carbon plant alone drives the higher constraint costs in non diverse zones and that carbon plant would not do so. For instance in 2.4 of the CMP268 consultation document, the proposer states our emphasis:

"*WACM2 proposed that the charging methodology could be even more cost reflective if it took account of the degree of diversity behind a network boundary. This was based on the reasoning that when the network flows on a particular circuit are dominated by generators who are very expensive to constrain off (due to high negative bid prices), then* ***those generators*** *will tend to cause a level of required network investment of those affected circuit at a level closer to 100% of their TEC instead of proportional to their ALF*."

However, as we have seen above, the workgroup actually said that "*for significantly expensive actions (negative bid price) the general assumption is that, in areas where this type of plant is dominant, TOs would build transmission network capacity at or very close* ***to the total generation capacity in the area concerned***" (our emphasis). That is, the TO would invest to meet the total amount of plant in the zone, both carbon and non carbon, as sharing in these circumstances is ineffective in reducing investment costs because of the low amount of lower cost bids available to the SO.

Therefore, it would be incorrect for an ALF to be applied to the Not Shared charge for carbon plant. It is not justified and would be less cost reflective than the baseline. Therefore it would simply introduce a cross subsidy for certain plant paid for by others. This would distort the wholesale generation market and also the outcome of the forthcoming Capacity Market.

The distributional effects of CMP268 are significant. It is cleverly designed to give a significant cost reduction to only a few stations at the expense of the rest of generators. Although this increases these other generators' charges by a relatively small £/kW figure, the relative competitiveness of the benefitting stations is increased significantly (by between £2/kW to £14/kW). In the context of the capacity market this could make the difference between a generator getting a capacity contract and it not. We note that the proposer must agree with this view, as it raised the modification urgently so that a decision could be made in time for this December's Capacity Auctions.

Therefore, we believe that CMP268 should not be implemented. The non cost reflective nature of the charge would work against charging objective b). The resultant cross subsidy will work to frustrate competition in the wholesale energy market in the longer term and also in the Capacity Market, working against charging objective a).

CUSC Workgroup Consultation Response Proforma

CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits'

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Respondent:	*Please insert your name and contact details (phone number or email address) Bill Reed* *Bill.reed@rwe.com 07795 355310*
Company Name:	RWE Generation UK plc, RWE Supply & Trading GmbH
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far

	as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses; (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.). *Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that CMP268 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	We do not believe that CMP268 Original proposal or any potential alternatives for change better facilitates the Applicable CUSC objectives. The introduction of sharing to the non-shared component of the tariff undermines the approach adopted for generation tariffs under CMP213. The CMP213 "Method 1" clearly establishes the principle that sharing between carbon and low carbon generators up to a defined level is based on the applicable load factor (ALF), and that beyond this level the capacity of the generators in a zone determines the non-shared investment signals applicable to the relevant parties. Therefore the non-shared component of the tariff cannot be shared by reference to the ALF. The CMP213 workgroup undertook rigorous analysis of the issue of sharing. Ofgem determined that the approach adopted was cost reflective and better met the applicable CUSC objectives. We have seen no new evidence that CMP268 is more cost reflective than the current baseline.
2	**Do you support the proposed implementation approach?**	No –we do not believe that this modification should be implemented.

Q	Question	Response
3	**Do you have any other comments?**	We are concerned that the urgent timescale prevents detailed consideration of the potential alternatives to sharing identified by the CMP213 workgroup. The alternative methods may better address the alleged defect than the approach identified under CMP268.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[1], and return to the CUSC inbox at cusc.team@nationalgrid.com* No

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

CUSC Workgroup Consultation Response Proforma

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Company Name:	*Please insert Company Name*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	For reference, the Applicable CUSC objectives are: **Use of System Charging Methodology** (a) that compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity; (b) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard condition C26 (Requirements of a connect and manage connection); (c) that, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission

	businesses; (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.). *Objective (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that CMP268 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?**	**Objective "a" effective competition** – Yes CMP268 does better facilitate effective competition for the reasons already outlined in the Workgroup consultation. **Objective "b" cost reflectivity -** Yes CMP268 does better facilitate effective competition for the reasons already outlined in the Workgroup consultation. Specific aspects in which CMP268 better meets the CUSC objectives includes the following: 1. **Better reflects sharing characteristics** - It better reflects the sharing characteristics of Conventional Carbon generators by no longer applying the Year-Round Not-Shared to 100% of their TEC. 2. **Better reflects operating characteristics of different Conventional Carbon generators** - It better reflects the different network investment cost caused by different characteristics of different Conventional Carbon generator though the application of their ALF to the Year-Round Not-Shared tariff element. This is because when low carbon generation dominates flows behind a boundary, then different Conventional Carbon generators will still cause different constraint costs proportional to whether they have a very low load factor (e.g. peaking plant), or a very high load factor (e.g. new entrant CCGT). 3. **Better enables a negative Peak Security tariff to provide a more effective economic price signal** - The purpose of a negative Peak Security price signal is to encourage dispatchable plant to locate in regions of the network where there is a shortage of dispatchable generation. However, this price signal is currently obscured by the existing CMP213 WACM2 methodology because even for a low load factor peaking plant, the magnitude of the Year-Round Not-Shared tariff element (designed to give a price signal to reduce the cost of constraints) charged at 100% of TEC tends to drown out the locational signal provided by the Peak Security tariff element. 4. **Better reflect cost with regard to generators in negative Year-Round Not-Shared zones** – The impact of CMP268 will be to dampen the negative price signal provided to Conventional Carbon plant in zones with a negative Year-Round Not-Shared tariff. This result is more cost reflective because the CMP213 WACM2 application of 100% of TEC currently over compensates Conventional Carbon generators for the benefit they provide to reduce constraints in zones with a negative Year-Round Not-Shared tariff. 5. **Appropriately, the locational tariffs of other generator types not affected** - It does not affect the status quo locational price signal provided for other types of generator (Low Carbon intermittent, or Conventional Low Carbon).

Q	Question	Response
2	**Do you support the proposed implementation approach?**	Yes. It is appropriate to implement the change at the earliest possible date for the charging year starting April 2017. This is supported by the following reasoning: 1. **Large financial impact those generators who are affected** – CMP268 would have a relatively large financial impact on a small number of directly affected generators. The magnitude of this impact highlights the importance to those generators of making this modification. 2. **Significant commercial impact relating to Capacity Auction** - Consistent with granting of urgent status by The Authority, it is appropriate that the implementation date for CMP268 should be at the earliest opportunity for charging year starting 2017/18. As described by Ofgem: "We accept the Proposer's case and have decided that CMP268 should be granted urgent status because of the potential significant commercial impact on some power plants linked to the timing of the next two CM auctions in December 2016 and January 2017."[1] 3. **Limited <u>direct</u> redistribution impact** – The analysis by National Grid contained in the Workgroup consultation demonstrated that there is only a small number (three) generators who would obtain a substantial direct benefit from the implementation of CMP213, namely Cruachan, Peterhead and Foyers. Meanwhile, there is only one single station which would be directly adversely affected, namely Seabank. Therefore the direct redistribution impact is relatively limited. 4. **Limited <u>indirect</u> redistribution impact** – The analysis of the impact on charges carried out by National Grid in the Workgroup Consultation indicated that the indirect impact on the Generation Residual may be only circa £0.17 per kW. This variation is well within the normal year to year variation which tends to be observed for generation tariffs, so can be considered to be relatively limited.. 5. **No impact on demand charges** – The demand tariffs are not affected by this proposal. 6. **The change is relatively simple** – The change to the CUSC is relatively simple to implement. The proposed modification to change the tariff formula is appropriate, as well as being a relatively simple and efficient method for achieving the objective of the modification proposal.

[1] Ofgem decision letter 23rd August 2016, CMP268 Workgroup Consultation Annex 5

Q	Question	Response
3	**Do you have any other comments?**	Please see three additional attached documents: 1. “**New analysis – evidence supporting CMP268**” – This report contains three parts of additional analysis in support of CMP268: i. Resulting Year Round tariff comparison of SQSS, CMP268 and Baseline (replicating the analysis Phil did for us on CMP213) ii. Empirical evidence that Conventional Carbon generators do tend to operate in a way which is consistent with CMP268 iii. Illustration of the feedback loop created by the Baseline application of the Not Shared Year Round tariff element 2. “**Review of previous analysis from CMP213**” – This collection of quotes and graphs was provided to the CMP268 workgroup, but not included in the annex to the report. This content is attached to this consultation response for completeness. **Comments regarding paragraph 4.7** “4.7 A Workgroup noted in their view that the CMP213 Workgroup report, flagged some members of the CMP213 Workgroup were concerned that “**small volumes of carbon in a predominantly low-carbon area would not be adequately recognised under this option**” (para 4.70) which highlights the issue raised in modification proposal CMP268. However it was noted that some members of the CMP213 Workgroup believed that method 1 was a “**better reflection of how the system was planned and so was more cost reflective overall**”. In this context a Workgroup member requested that National Grid should consider whether the approach under CMP213 WACM2 better reflected transmission investment planning decisions when compared with CMP268.” [emphasis added] This comment in the CMP268 Workgroup consultation conflates two different quotes from different sections of the original CMP213 Workgroup report (one from para 4.70 and one from two paras later 4.72 which was talking about something completely different) in a way which completely changes the meaning and entirely misrepresents the original text in the CMP213 workgroup report. In the CMP213 Report,

Q	Question	Response

when the second quote refers to "…better reflection of how the system would be planned and so was more cost reflective overall." (4.72), in its original context, this quote refers to a comparison between CMP213 WACM2 as being better than the then Baseline (pre CMP213). The comment is misleading because it erroneously attempts to imply that when the quote refers to "better" it is comparing CMP213 WACM2 with some hypothetical alternative of adequately recognizing the benefit of "…small volumes of carbon in a predominantly low-carbon area…" which was not the meaning of the original context of the quote at all**.** For clarity, the CMP213 workgroup process did not include an alternative equivalent to CMP268. For reference, I have attached the two paragraphs where the quotes were taken from the CMP213 Workgroup Report so people can see how unrelated they are:

> **"Some Workgroup members also felt that the true benefit of small volumes of carbon in a predominately low-carbon area would not be adequately recognised under this option**, as all generation behind a boundary would be subject to the same overall sharing factor past the 50% sharing point. For example, if you have a zone with large amounts of low carbon generation, and a carbon generator connects, there may still be minimal sharing deemed to take place, and therefore the carbon generator's TNUoS charge will be based predominately on capacity, even though the carbon generator is sharing 100% with low carbon generation." (4.70) [emphasis added]
>
> "Other Workgroup members felt the Method 1 diversity alternative would also increase volatility in TNUoS tariffs. This is because the amount of sharing is adjusted when new generation becomes part of the transmission network behind a boundary. This means that third party decisions on where to site their generation plant would affect the level of sharing behind that boundary. For example, if a greater amount of low carbon generation entered the area and pushed low carbon over the 50% point, sharing would be further reduced in line with the percentage reduction. These Workgroup members argued that this would make it difficult for Users (especially smaller parties) to predict their TNUoS charges over the medium term (leading to market uncertainty). Others argued that as diversity is considered on a boundary level, that new generation would have a much less significant impact on an individual User's TNUoS tariffs, as for the majority of the transmission system, carbon / low carbon sharing would be considered across multiple charging zones." (4.71)
>
> "Some Workgroup members argued that this Method was not favourable as it treats Users differently in different parts of the transmission system on the basis of the calculation of their charges (from capacity to commodity). **For example in areas with significant low carbon generation deployment, the majority of MWkm are charged on a capacity (TEC) basis whereas in areas with significant carbon generation deployment the majority of MWkm are charged on a pseudo-commodity basis based on ALF. Supporters of Method 1 largely agreed that this was the effect, but that it was a better reflection of how the system would be planned and so was more cost reflective overall.** They noted the analysis performed on areas with little diversity / expensive bids demonstrated that intra zonal investments would be based more on generation capacity rather than generation load factor." (4.72) [emphasis added]

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*If yes, please complete a WG Consultation Alternative Request form, available on National Grid's website[2], and return to the CUSC inbox at* cusc.team@nationalgrid.com

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

New analysis – Evidence supporting CMP268

This report includes new analysis which provides further evidence in support of CUSC modification proposal CMP268. The analysis is described in three sections:

1. Resulting Year Round tariff comparison of SQSS, CMP268 and Baseline
2. Empirical evidence that Conventional Carbon generators do tend to operate in a way which is consistent with CMP268
3. Illustration of the feedback loop created by the Baseline application of the Not Shared Year Round tariff element

1. Resulting Year Round tariff comparison of SQSS, CMP268 and Baseline

SSE carried out analysis comparing the Year Round TNUoS charges by generation charging zone which would result from the implementation of CMP268. These charges were compared with the charges using the Baseline methodology and the charges which would result from using the SQSS scaling factors[1] for a range of different types of generator including Peaking, CCGT, nuclear and wind. This used the tariffs from National Grid published June 2016 Quarterly Update 2017-18[2].

The analysis in the graphs below highlight that CMP268 will tend to result in Year Round TNUoS charges which are more cost reflective for Conventional Carbon plant with operating characteristics which result in an ALF anywhere between 0% and 100%. This is because the analysis demonstrates that CMP268 is more cost reflective of the SQSS for a zero (or very low) ALF generator, while it is as cost reflective as the Baseline for Conventional Carbon generators with a very high ALF and CMP268 also tends to be more cost reflective than Baseline in the method it calculates charges for Conventional Carbon generators which have an ALF anywhere in the range of 0% and 100%.

To understand why CMP268 is more cost reflective across a range of Conventional Carbon generators with different ALFs, it is helpful to understand the interaction between the SQSS and a full-blown Cost Benefit Analysis. The SQSS scaling factors are best considered as a form of "average" approximation which is cost reflective of a full blown Cost Benefit Analysis. It is therefore reasonable to conclude that in reality generators with operational characteristics which may be different from the SQSS "average" (higher, or lower) may be expected to cause a different (higher, or lower) cost within a CBA analysis and it is therefore reasonable that this difference from SQSS "average" be taken account of in the charging methodology. Baker described this relationship as follows:

"The aim of a cost-reflective charging methodology must be to apply charges that reflect the **actual costs incurred** in accommodating additional generation capacity. However, it is important to note that the pseudo-cost benefit approach (CBA) dual background methodology [of the SQSS] is no more than a deterministic short-hand for the full-blown CBA used to justify individual transmission investment decisions**. It [SQSS] is best considered as representing the "average" outcome of a range of full CBA studies**" [3] [emphasis added]

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[1]

[2] http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

[3] Review for SSE of Poyry's Report to Centrica Energy "Review of Ofgem's Impact Assessment on CMP213, P E Baker, March 2014.

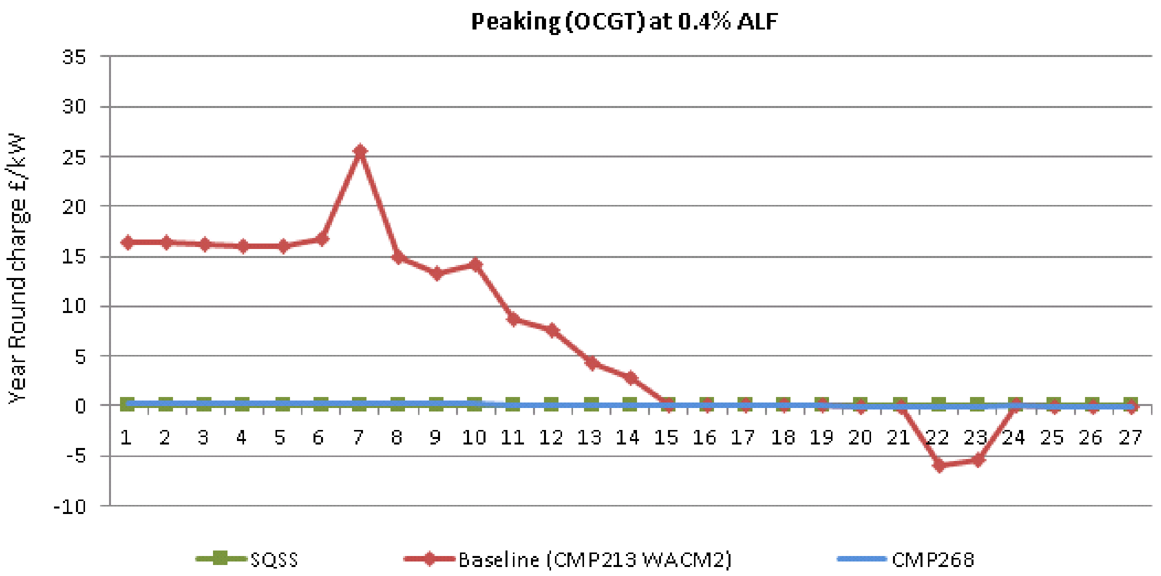
1.1. More cost reflective for Peaking (OCGT) generators

The improved cost reflectivity of CMP268 is most apparent when considering the case of a peaking plant such as an OCGT. The graph below illustrates that the Year Round TNUoS charge for an OCGT arising from CMP268 would be almost identical to that derived from using the SQSS scaling factor. This is because for an OCGT, the SQSS uses a scaling factor of zero, while for a station with an ALF of zero (or very close to zero), then CMP268 would result in an identical, or almost identical Year Round charge. By contrast, the Year Round TNUoS charge for this class of generator resulting from the Baseline is much less cost reflective because it its application of 100% to the Not Shared Year Round tariff element results in charge which is much higher than SQSS in Northern zones and much lower than SQSS in zones 22 and 23 which exhibit a substantial negative Not Shared Year Round tariff.

The rational for the zero scaling factor for OCGTs within the SQSS is that this type of generator will tend to have a negligible contribution to constraint cost, therefore a negligible contribution to the cost of network investment associated with the Economy Criterion of the SQSS.

This analysis suggests that CMP268 would be considerably more reflective of the cost of investment indicated as required via the SQSS than Baseline for this class of generator.

As described in the document provided by SSE "Review of previous analysis from CMP213", this result concurs with analysis previously described in the CMP213 Workgroup Report[4], as well as evidence provided separately by Baker, Poyry[5] and NERA/Imperial.[6]



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https://www.ofgem.gov.uk/sites/default/files/docs/2014/04/review_for_sse_of_poyrys_report_to_centrica_energy_titled_review_of_ofgems_impact_assessment_on_cmp213_0.pdf

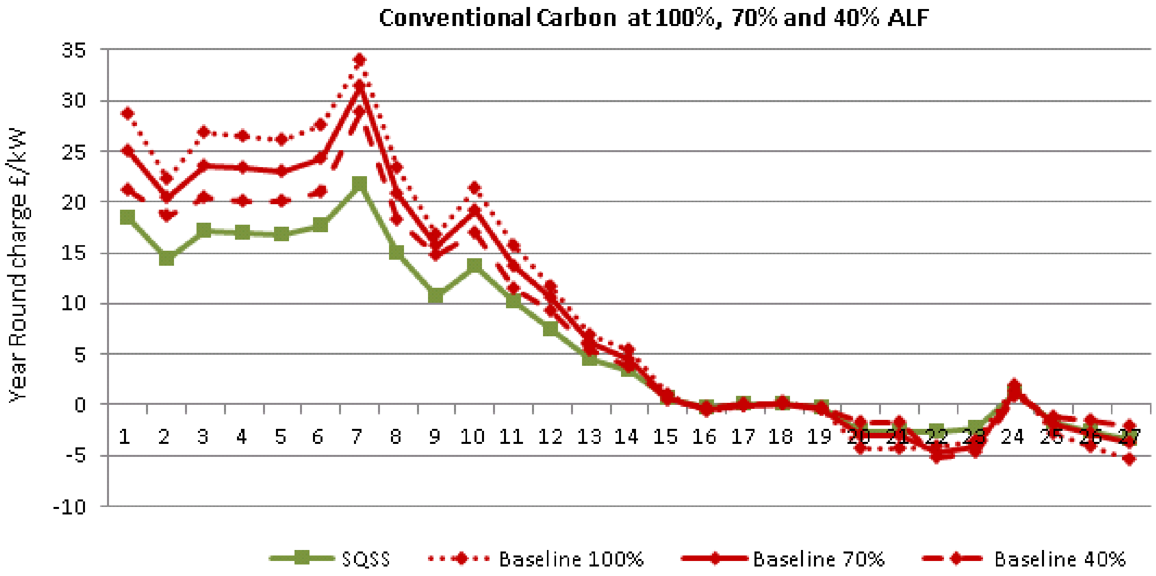
[4] CMP213 Final CUSC Modification Report Volume 1 http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

[5] REVIEW OF OFGEM'S IMPACT ASSESSMENT ON CMP213, Poyry October 2013 https://www.ofgem.gov.uk/ofgem-publications/85135/consultationresponsefromcentrica2.pdf

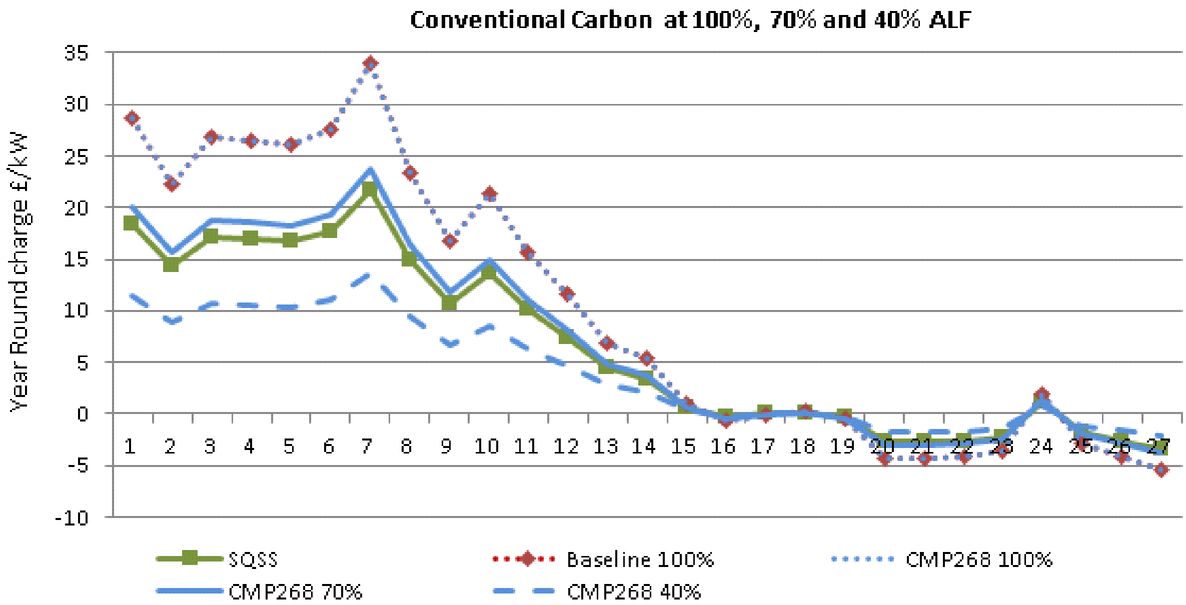
[6] Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA & Imperial College London, February 2014 http://www.nera.com/content/dam/nera/publications/2014/CostReflectivityReport.pdf

1.2. More cost reflective for CCGT generators

The graph below illustrates that for a Conventional Carbon generator such as a CCGT, with an ALF ranging between 40%, 70% and 100%, the charges derived from the Baseline methodology would all be higher in Northern zones than that implied by the SQSS scaling factors. It would therefore appear that the Baseline methodology is over charging Conventional Carbon generators in these zones.



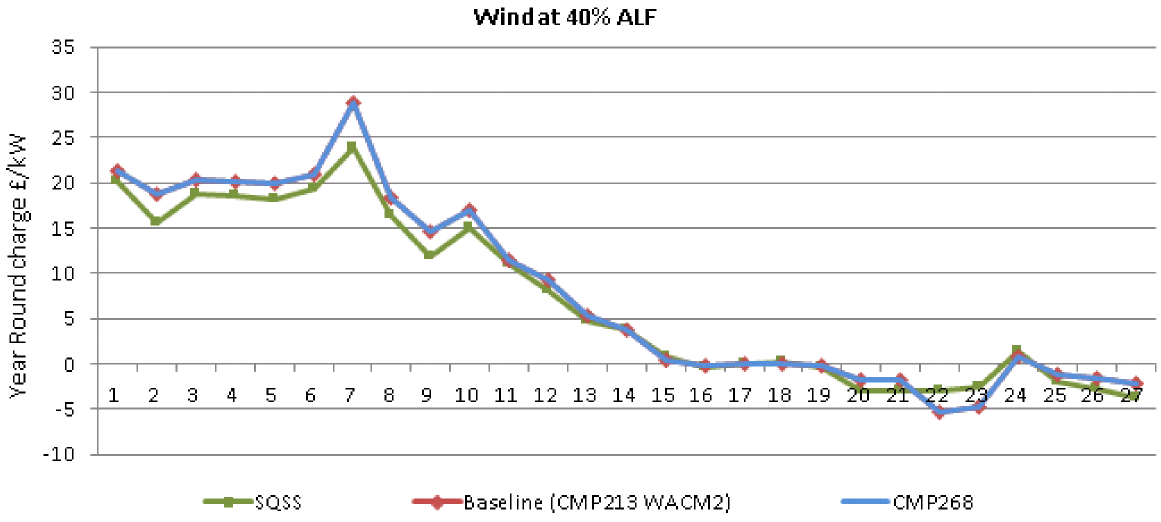
The graph below shows a similar set of tariffs derived from the CMP268 methodology from which three key conclusions can be drawn. Firstly, it shows that for a notional 100% ALF generator, CMP268 would provide a set of Year Round charges that are identical to the Baseline, therefore for a notional 100% ALF generator, CMP268 is equally cost reflective compared with Baseline. Secondly, the graph illustrates that for a Conventional Carbon generator with an ALF of 70%, CMP268 would result in a set of tariffs which are very close to the SQSS. Thirdly, for CCGTs with a relatively low ALF, the CMP268 methodology would provide a set of charges which tend to converge towards those provided by the SQSS for a Peaking plant (0% scaling) which is consistent with low ALF CCGTs exhibiting operating characteristics which are in practice closer to those of a peaking OCGT. This result is consistent with expectation because the SQSS scaling factor by definition represents a form of average, so there will always tend to be some individual stations which tend to cause a network investment cost higher than that indicated by the SQSS and others which tend to cause a cost of investment lower than that indicated by the SQSS.

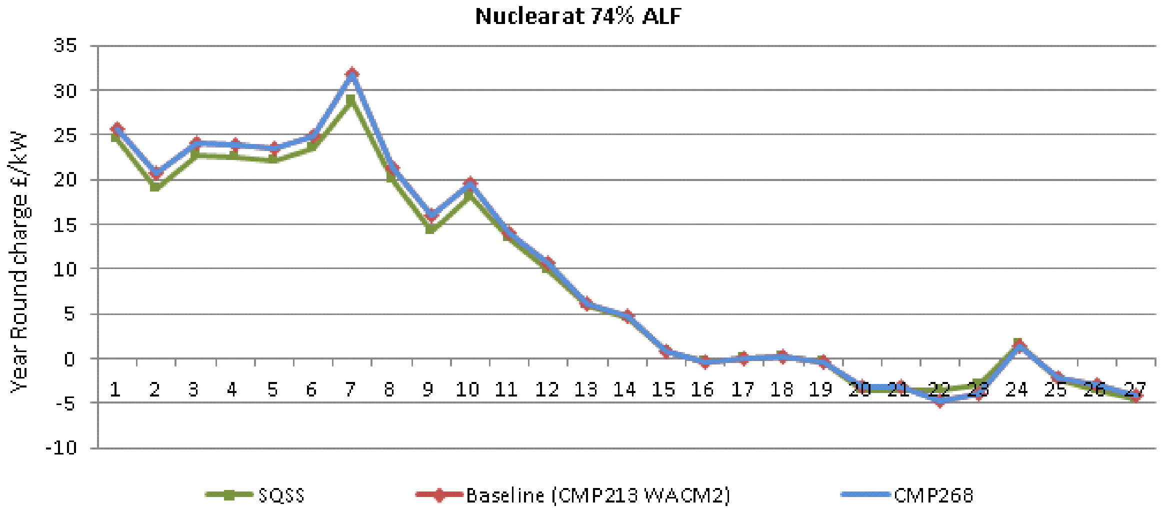


1.3. Equally cost reflective for Low Carbon generators (Wind and Nuclear)

The two graphs below illustrate that CMP268 would provide Year Round charges which are identical to those provided by the Baseline charging methodology for Low Carbon generators (wind and nuclear), both of which appear to be closely cost reflective of the SQSS.

This is illustrated by a 40% ALF wind farm in charging zone 1 paying 40% of the Shared Year Round tariff and 100% of the Not-shared Year Round tariff, which for zone 1 provides a weighted average charge of £ 21.22 per kW (0.4x£12.46 plus 1x£16.24 = £21.22). This charge equates to 74% of the combined Year Round tariff (£21.22 divided by £28.7), which is very close to the SQSS scaling factor of 70% for wind farms.





The table below shows the scaling factors used for the SQSS comparison:

	SQSS
Wind	70%
Conventional	64%
Nuclear	85%
Peaking	0%

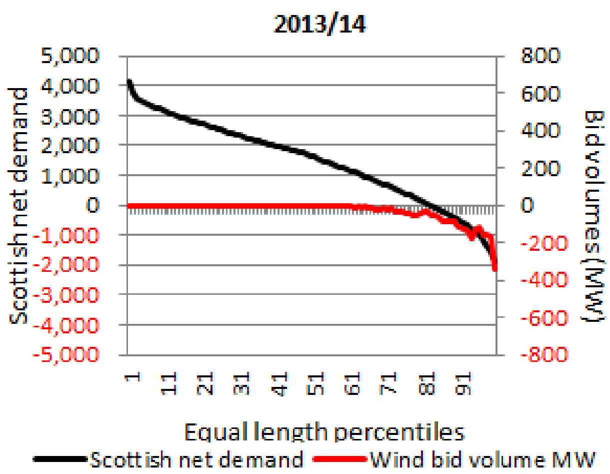
2. Empirical evidence that Conventional Carbon generators do tend to operate in a way which is consistent with CMP268

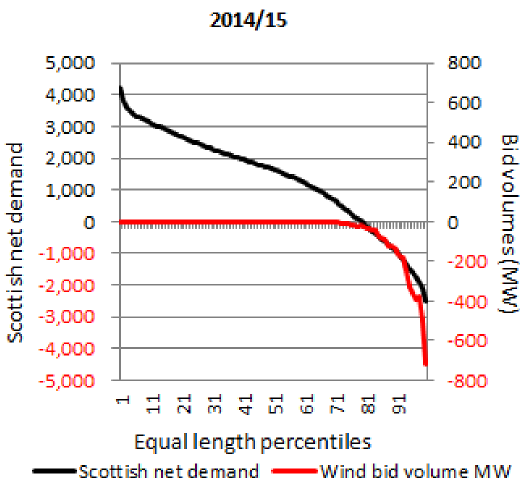
SSE carried out analysis comparing MWh volumes for FPNs, Bids and Offers for Conventional Carbon generators (CCGT and Pumped Hydro) in Scotland compared with net demand in the three financial years of 2013/14, 2014/15 and 2015/16. This analysis suggested that the historic operational characteristics of Conventional Carbon generators has been consistent with the principles of sharing used in both the Baseline and CMP268.

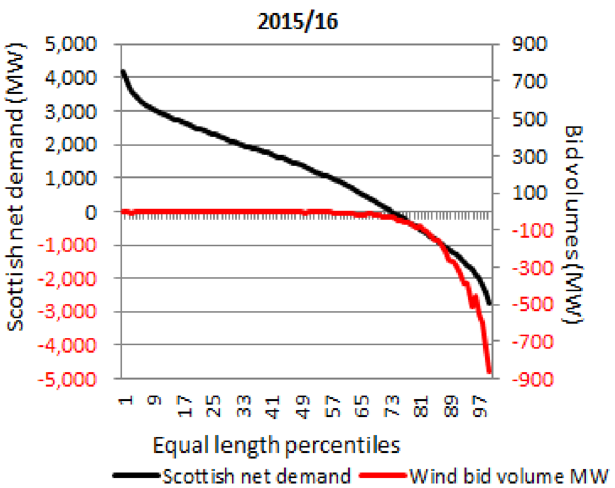
Scottish net demand was calculated as Scottish demand minus Scottish wind generation. This used National Grid published INDO demand, adding back in embedded wind, then applying a 9% pro-rata adjustment[7] to derive an equivalent figure for Scottish demand. Scottish wind was calculated from all transmission connected wind farms in Scotland, with a pro-rata increase to match the total installed capacity of wind in Scotland.

2.1. Scottish net demand is closely correlated with constraint cost

The graphs below show net demand (INDO - Scottish wind) sorted into percentiles plotted against accepted bid volumes (MW) from wind. This demonstrates that the level of Scottish "net demand" is a good measure of the likelhood that a particular half hour period may include expensive constraint payments to curtail wind generation in Scotland. This is because the periods of high bid volumes of Scottish wind are associated withperiods of low net demand in Scotland and importantly, economic merit order suggests that dispatchable peaking generators are less likely to be running during those low net demand periods.



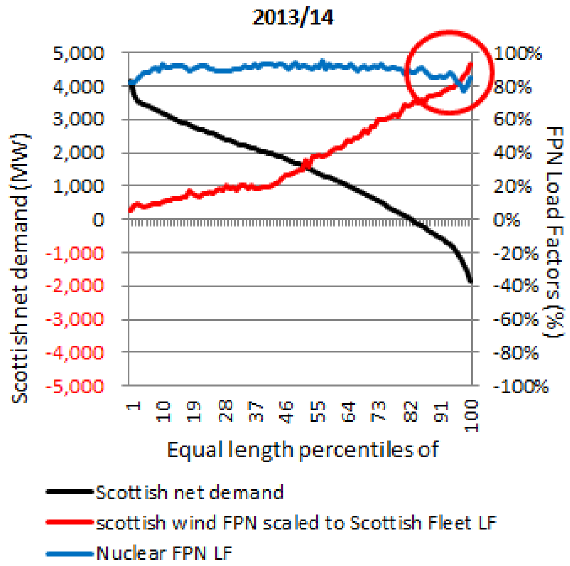


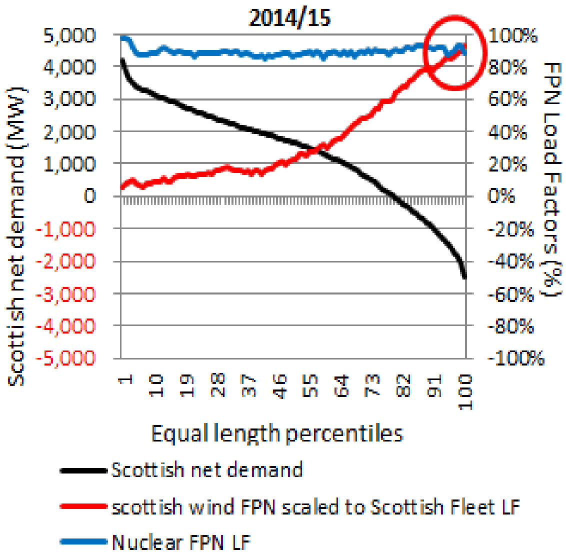


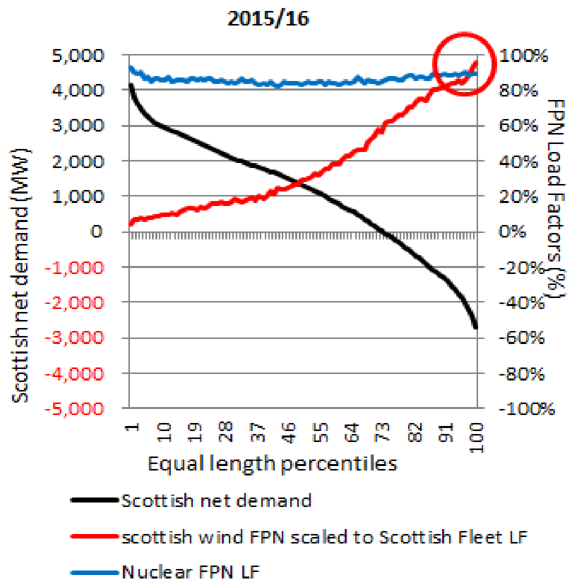
[7] Based on Ofgem published Renewables Obligation eligible demand for Scotland as a % of GB eligible demand https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-total-obligation-201516

2.2. Low Carbon generation correlated with periods of constraint

The graphs below illustrate the same periods of net demand (INDO - Scottish wind) sorted into percentiles, but this time plotted against the FPN Load factors (%) of Scottish Low Carbon generation (nuclear and wind). This illustrates that these classes of Low Carbon generators have historically exhibited relatively high load factors close to 100% during periods of relatively high constraints volume. This relatively high correlation with periods of constraints combined with the relatively expensive bid prices means that when Low Carbon generators have limited capacity of Carbon generation to share with, then Low Carbon generators may tend to cause a network investment cost which is close to their full capacity. This result is broadly consistent with the continued application of 100% of the Not Shared Year Round tariff element for Low Carbon generators which is used by the Baseline and which remains unchanged following the implementation of CMP268.



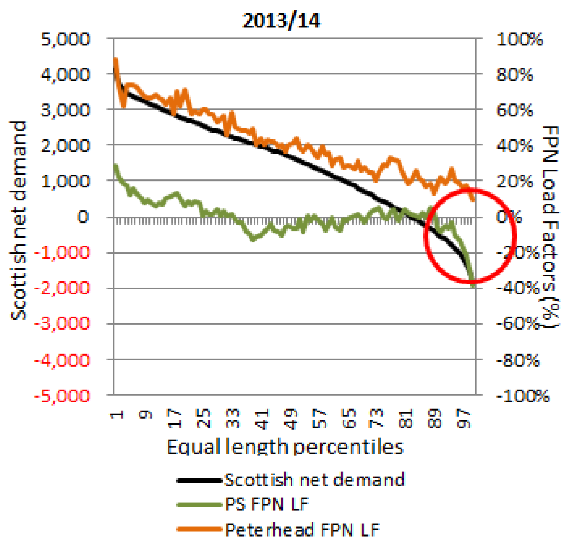


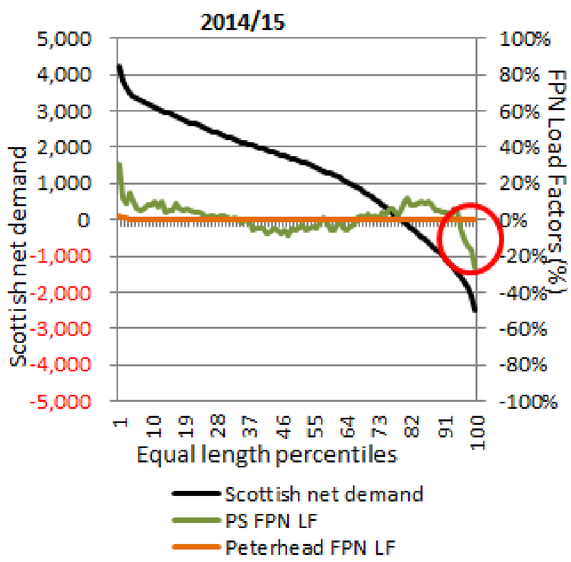


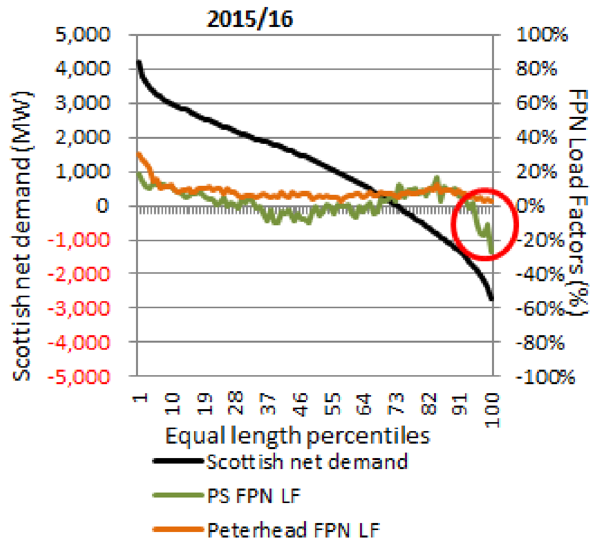
2.3. Marginal Conventional Carbon generation is inversely correlated with periods of constraint

The graphs below are the same format as those above, except this time plotted against the FPNs of Scottish Conventional Carbon generators. These graphs illustrate that these Conventional Carbon generators (Petherhead and Pumped Hydro storage) are inversely correlated with periods of constraint. This means that during periods when constraints are most likely, then the load factor of these stations is relatively close to zero, so the cost of constraints which they are contributing to is relatively small compared with their installed capacity. This inverse correlation combined with their relaitvely inexpensive bid prices means that they will tend to cause relatively limited network investment cost for the purpose of managing constraints, even if the boundery they are behind is dominated by Low Carbon generation. This result is contrary to the Baseline methodology which charges these stations 100% of the Not Shared Year Round tariff and this result is key to the defect which the CMP268 proposal is designed to correct.

Peterhead was not operating commercially in the wholesale market during 2014/15, or 2015/16, so the data shows its FPNs being at, or close to zero in those years. The non zero FPNs of Peterhead represent generation during a small number of months.

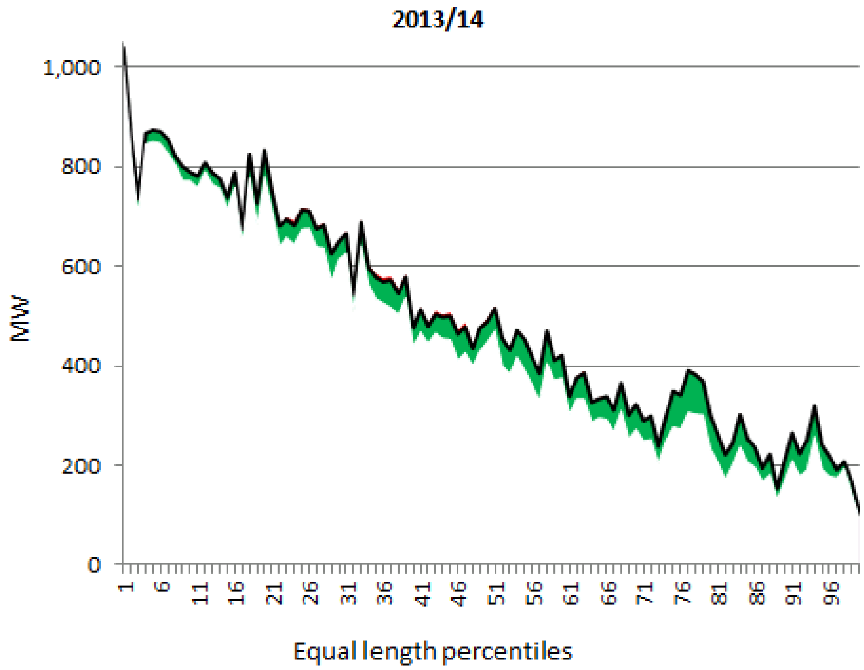






2.4. Marginal Conventional Carbon Generator (Peterhead) not being "Offered on"

The graph below shows for Peterhead the combination of FPN, as well as Bids and Offers taken. The volume of bids taken is haded in green, while the volume of offers taken is shaded red (offer volumes are difficult to see on the graph because the volumes are so low). This illustrates that when Peterhead was operating on a commercial basis within the wholesale market, there was no significant systematic requirement for the System Operator to constrain on (offer on) Peterhead for system reasons. This pattern of dispatch is consistent with generation volume metered data.



2.5. Longannet operational characteristic

The graphs below illustrate Longannet FPNs compared with the volume of Bids and Offers which were taken. This results shown further support the proposed CMP268 approach of applying Conventional Carbon generator's ALF to their Not Shared Year Round tariff instead of the 100% used within the Baseline.

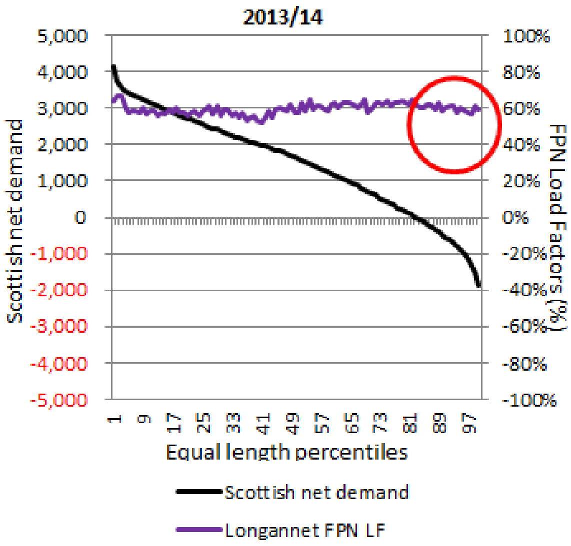
The volume of Bids taken (reduced output) are shown in the green shaded area. The volume of Offers taken to increase output are shown in the red shaded areas, note this it is difficult to see these volumes on the graph because the volumes were relatively small.

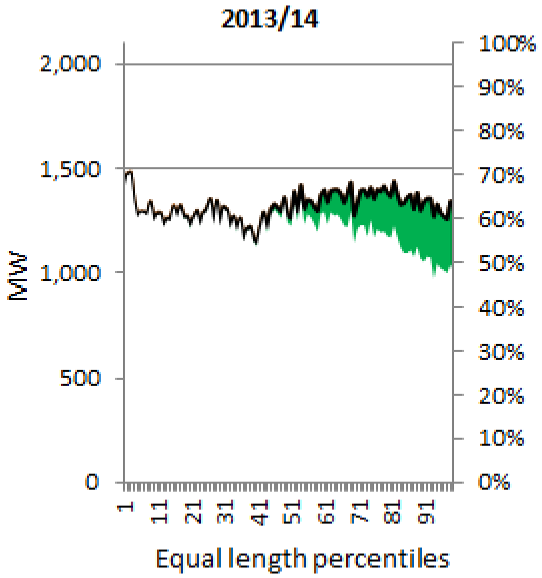
This analysis illustrates that in all years, Longannet's average load factor during periods when constraints are most likely tended to be in the range of 30% to 60% which is substantially lower than its full capacity.

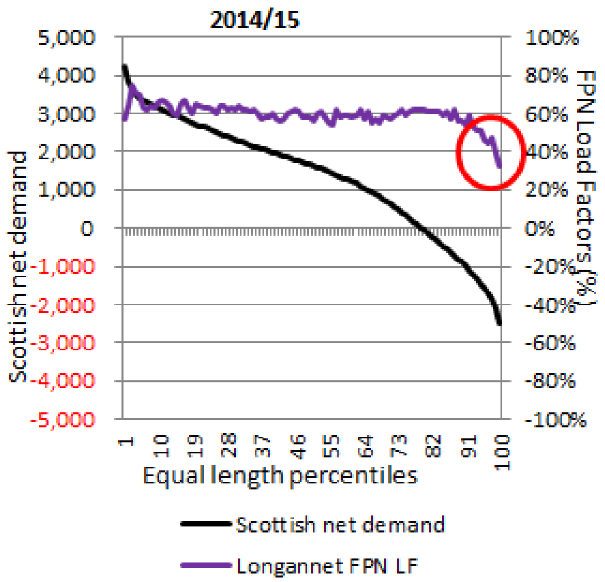
Further the analysis shows the average bid volume during those periods tended to reduce Longannet's generation load factor further by up to 20% compared with its FPN. This is an illustration of periods when Longannet could be bid off at a relatively low cost (compared with Low Carbon generation such as wind or nuclear) to avoid constraints.

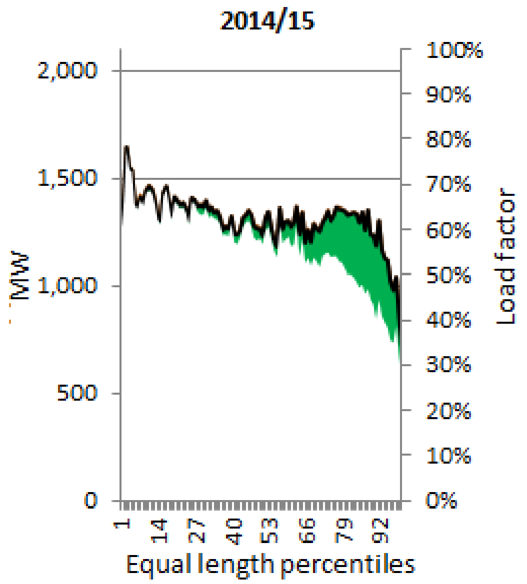
It would appear that the generation output of Longannet after bids had been taken tended to be higher than that for Peterhead (30% to 50% for Longannet, compared with 0% to 20% for Peterhead), so it may be concluded that the operational characteristics of Longannet tended to cause more constraints than Peterhead. This result is consistent with the respective ALFs of the two stations, for 2016 with Longannet at 55% and Peterhead at 42%[8].

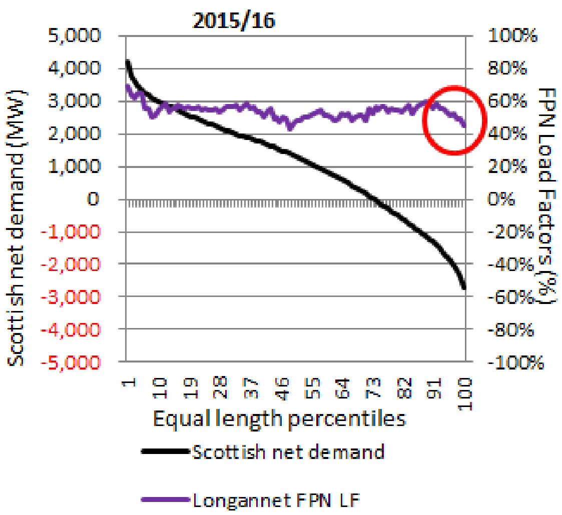
[8] Annual Load Factors for 2016/17 Generation TNUoS Charges, National Grid January 2016 http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/

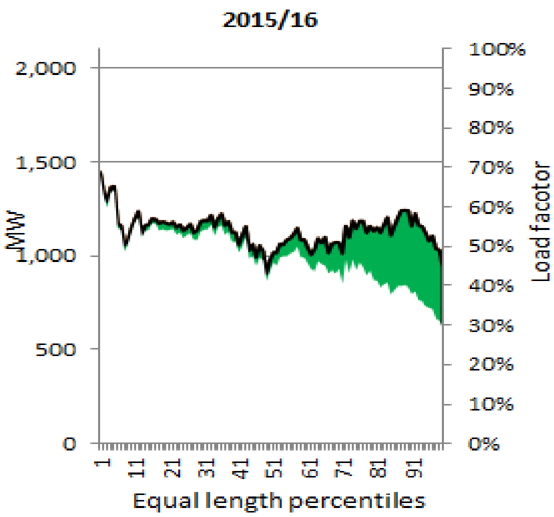

2013/14
Scottish net demand
FPN Load Factors (%)
Equal length percentiles
Scottish net demand
Longannet FPN LF


2013/14
MW
Equal length percentiles


2014/15
Scottish net demand
FPN Load Factors (%)
Equal length percentiles
Scottish net demand
Longannet FPN LF


2014/15
MW
Load factor
Equal length percentiles


2015/16
Scottish net demand (MW)
FPN Load Factors (%)
Equal length percentiles
Scottish net demand
Longannet FPN LF


2015/16
MW
Load facotor
Equal length percentiles

3. Illustration of the feedback loop created by the Baseline application of the Not Shared Year Round tariff element

SSE carried out analysis using the ICRP Transport Model for 2017/18 as published by National Grid to accompany the June 2016 Quarterly Update 2017-18 to derive locational TNUoS tariffs across a range of sensitivities. The Model was used as published with the following adjustments to test sensitivities:

1. Variation of MW capacity of Conventional Carbon Generation in Scotland, specifically Peterhead, Foyers and Cruachan. The sensitivity was applied to all three on a pro-rata basis to avoid making any judgement regarding particular station investments.

2. Increase in MW capacity of wind farms in Scotland

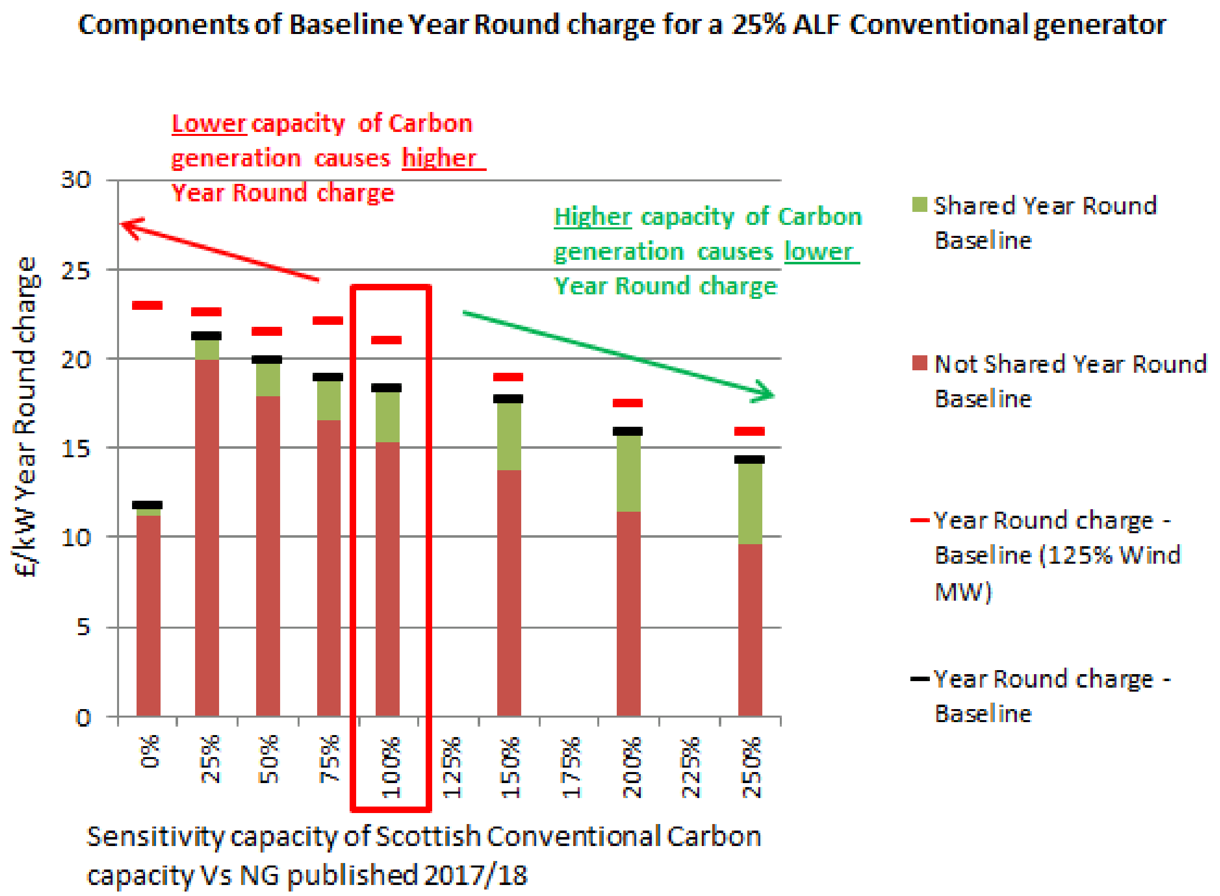
3.1. Baseline treatment of Not Shared Year Round tariff element causes a feedback loop

The graph below illustrates the feedback effect which tends to be caused by the application of the Baseline Not Shared Year Round tariff methodology. This shows the impact of sensitivities to the installed capacity of Carbon generation in Scotland (Peterhead, Foyers and Cruachan) as compared with the capacity listed in the National Grid published ICRP Transport model associated with the June Quarterly update of TNUoS tariffs for 2017/18. The x-axis shows the sensitivity assumption regarding pro-rata adjustment to the installed capacity of Carbon generation in Scotland ranging between 0% and 250% of the National Grid published capacity (100% is equal to the National Grid published capacity).

This demonstrates that the Baseline combined Year Round charge tends to become more expensive as the capacity of Carbon generation is reduced because this causes a reduction in assumed sharing, so a relative increase in the proportion of the Year Round tariff which is defined as “Not Shared”, on which Conventional Carbon generators currently pay 100% of their TEC. This tends to create a feedback loop because the higher share of the “Not Shared” element tends to an increase in the combined Year Round charge, which tends to provide an even stronger price signal for the remaining Conventional Carbon generators to also close. The reverse is also the case that the higher the capacity of Conventional Carbon generators locating in Scotland would tend to cause a reduction in the combined Year Round charge, which would tend to make Scottish zones relatively more financially attractive for future additional Conventional Carbon generators, so tend to create a feedback loop of additional investment.

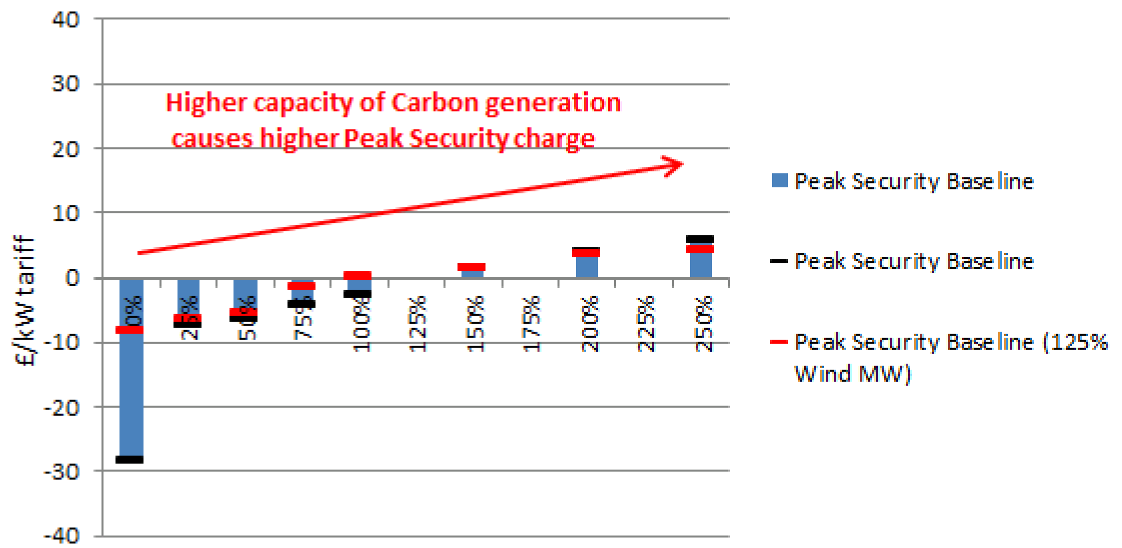
The horizontal red bars shows the same result, but using the additional sensitivity assumption of a 25% increase in the capacity of wind in Scotland. This sensitivity highlioghtes that with the additional weind capacity, the feedback loop of increasingly expensive Year Round charges would continue all the way down to a zero capacity of Conventional Carbon generation in Scotland.

The graph below illustrates this feedback effect on the Year Round TNUoS charges within the Baseline CMP213 WACM2 charging methodology for a Conventional Carbon generator with an ALF of 25% in Charging Zone 1.



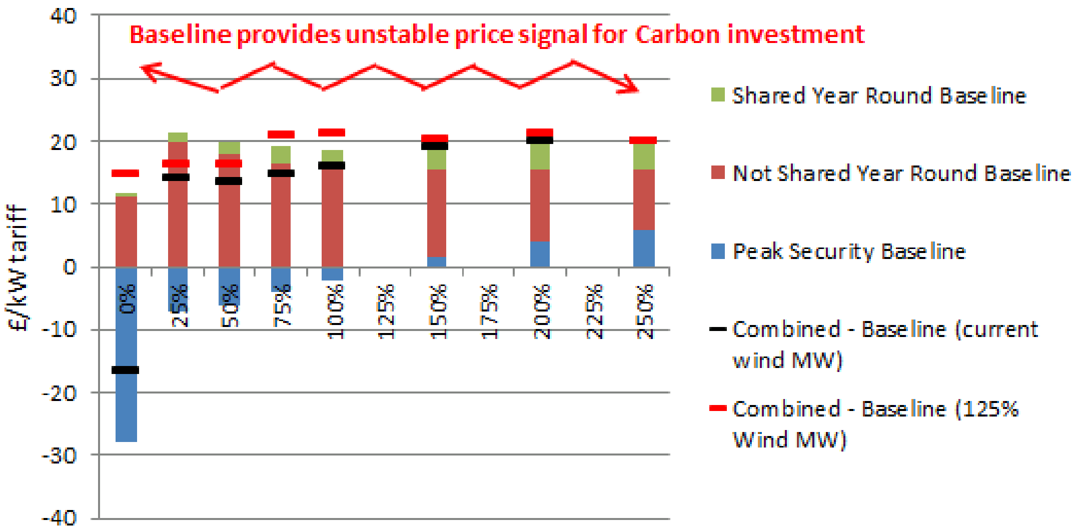
3.2. Baseline Peak Security tariff tends to provide opposite price signal to Baseline Year Round

The graph below takes the same approach as the graph above, illustrates the impact of the same scenarios for the Peak Security tariff element. This demonstrates that as the Capacity of Conventinal Carbon generation reduces, the Peak Security price signal tends to become cheaper i.e. it tends to provide an increasingly strong incentive for Conventional Carbon plant to locate in Scottish zones to reduce the cost of the network with regard to investment required to provide Demand Security.



3.3. Baseline combination of Year Round and Demand Security tariff elements provide unstable incentives

The graph below illustrates the issue that signal arising from the methodology for calculating the large positive Baseline Not Shared Year Round charge tends to be large enough to drown out the opposite price signal prioivided by the negative Peak Security tariff. The net charge tends to be unstable and does not to provide an incentive to tend towards an equilibrium balance of Conventional Carbon plant i.e. there is not a systematic relationship between a higher, or lower capacity of Conventional Carbon plant and a resulting change in TNUoS locational price signal. This is an undesirable characteristic for a price incentive mechanism.



3.4. CMP268 does provide price signal that leads to a rational incentive for investment to converge to equilibrium

The same tariffs were applied using the proposed CMP268 tariff formula with the resulting charges for a Conventional Carbon generator as illustrated in the graphs below. This demonstrates the following beneficial characteristics of proposa, CMP268:

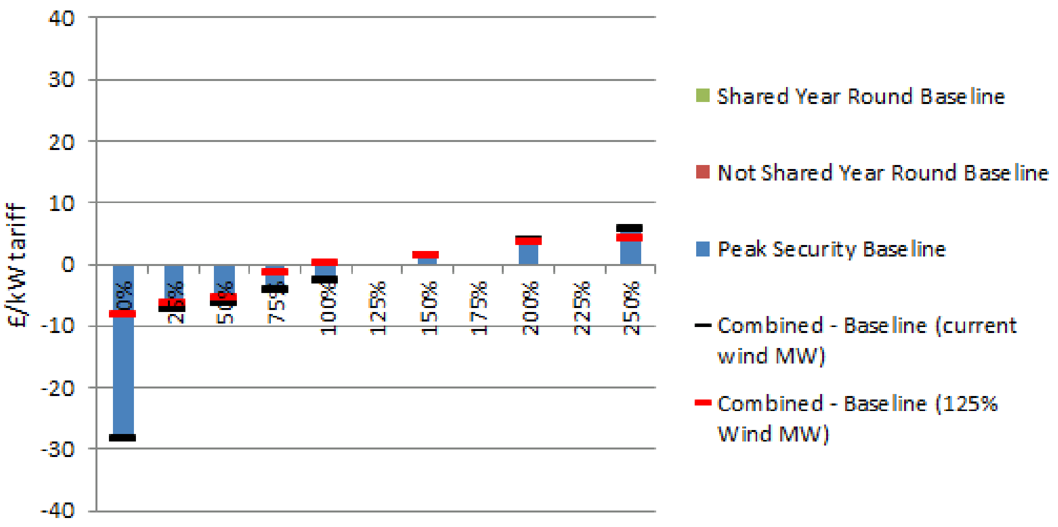
1. **Price signals tend towards equilibrium** – In contrast to the Baseline charging methodology, the set of price incentives provided by CMP268 do tend towards an economic equilibrium. This occurrs because the transmission price signal for Conventional Carbon generators in Scotland tends to become more expensive when more capacity is built and correspondingly cheaper when capacity is closed.

2. **More appropriately different charges for different generators** – Graphs below illustrate:
   a. **For a 0% ALF generator** - The price signal it receives is driven by the Peak Security tariff element, which is consistent witht the SQSS treatment of OCGTs. This illustrates that if there were to be a closure of dispatchable generation in Scotland, then the price signal would tend to charge provide a stronger incentive to invest in low load factor peaking plant in affected zones. This is consistent with the intuitive result that a zone dominated by wind generation would tend to be a relatively good location (from a network cost point of view) to locate a low load factor peaking generator

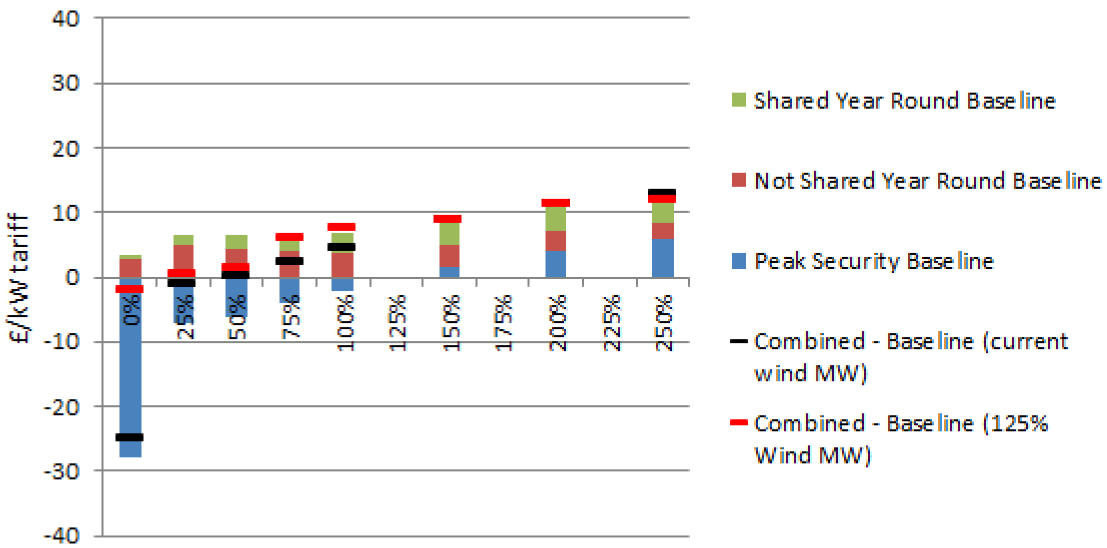
   b. **For a 25% ALF generator** – The price signal it receives is a balance of the Peak Security and Year Round tariffs. This appropriately demonstrates that if the capacity of Conventional Carbon generation in Scotland reduced, then the negative Peak Security price signal would become increasingly dominant, while if the capacity of Conventional Carbon generation in Scotland increased, then the more expensive positiev Year Round charge would tend to become increasingly dominant.

   c. For a 75% ALF generator – The price signal remains expensive for this type of generator (such as a high efficiency new entrant CCGT) in Scotland across almost all scenarios. This is consistent with the intuitive result that a zone dominated by wind generation would tend to be a relatively poor location (from a network cost point of view) to locate a high load factor baseload generator.

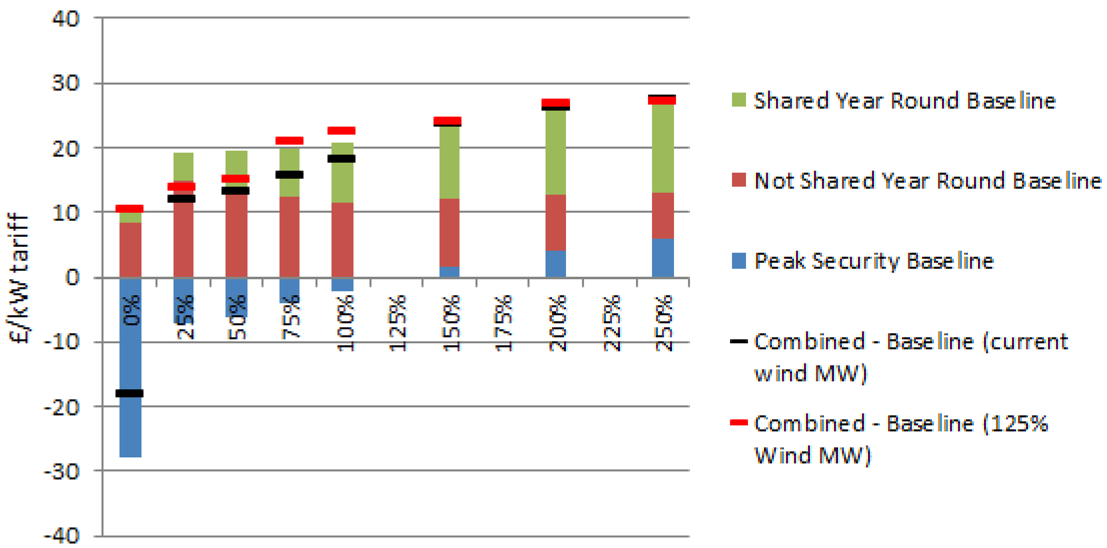
CMP268 - 0% ALF



CMP268 - 25% ALF



CMP268 - 75% ALF



Review of previous analysis from CMP213

The proposer provided to the CMP268 Workgroup the following collection of references from analysis which was previously carried out during the process of CMP213. The proposer presented this evidence to the CMP268 Workgroup and explained how this evidence supports the CMP268 proposal as described in the CMP268 Workgroup Consultation section “Proposer’s Presentation”.

This evidence presented is described below in 8 sections:

1. Economic rationale behind network sharing
2. Circumstances where sharing is reduced
3. Evidence – Simplified two node model
4. Evidence – ELSI Market Model
5. Evidence - Cost reflectivity compared with SQSS
6. Evidence - Alternative modelling of cost reflectivity
7. Evidence - From NERA/ICL for RWE – Cost reflectivity Vs LRMC
8. Evidence from Poyry for Centrica

The sources for the evidence were taken from the following

1. **CMP213 Final CUSC Modification Report Volume 1**
   http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

2. **CMP213 Final CUSC Modification Report Volume 2, Annexes**
   http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

3. **Review for SSE of Poyry’s Report to Centrica Energy “Review of Ofgem’s Impact Assessment on CMP213, P E Baker, March 2014.**
   https://www.ofgem.gov.uk/sites/default/files/docs/2014/04/review_for_sse_of_poyrys_report_to_centrica_energy_titled_review_of_ofgems_impact_assessment_on_cmp213_0.pdf

4. **Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA & Imperial College London, February 2014**
   http://www.nera.com/content/dam/nera/publications/2014/CostReflectivityReport.pdf

5. **REVIEW OF OFGEM'S IMPACT ASSESSMENT ON CMP213, Poyry October 2013**
   https://www.ofgem.gov.uk/ofgem-publications/85135/consultationresponsefromcentrica2.pdf

1. Economic rationale behind network sharing

"The Workgroup agreed that annual incremental constraint costs for each generator with a given TEC (i.e. £/MW/annum) are comprised of two main components, illustrated below in Figure 5 which could be further sub-divided into five variables." (Final CUSC Modification Report Volume 1, 4.19)

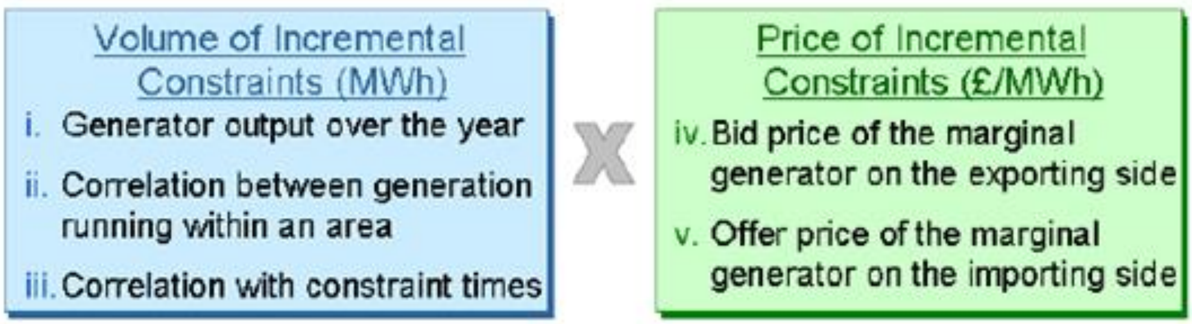


Figure 5 – Components that drive transmission constraint costs

"The effect of these elements (in terms of whether they have an upward or downward effect) on the total incremental costs of constraints is shown below in Figure 6. Some elements such as generator output over the year, the coincidence of running at time of constraint and the impact of bid/offer prices all lead to higher total incremental constraint costs as they increase. **Conversely, if there is decreased correlation between generation running in an area of the transmission network (non-coincident running), this lessens the overall impact on incremental constraint costs**." (Final CUSC Modification Report Volume 1, 4.20) [emphases added]

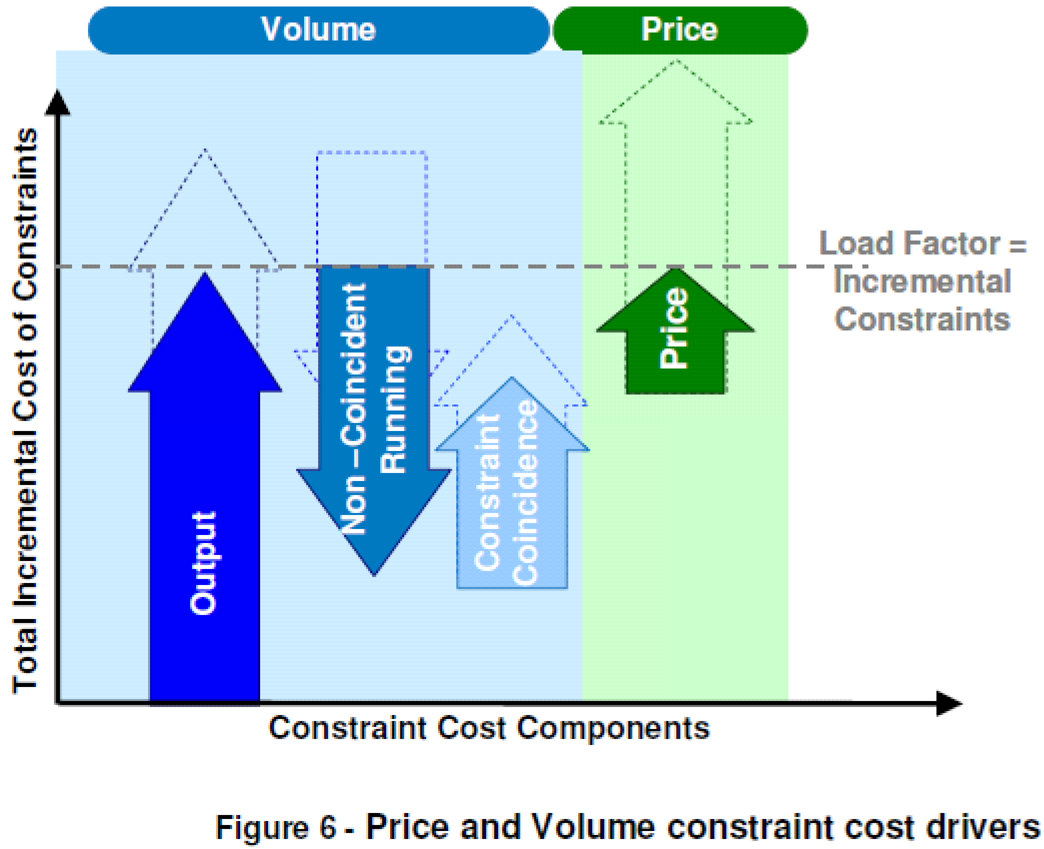


Figure 2: Taken from "Figure 6" of CMP213 Workgroup Final report.

"In search of a method for taking into account the many characteristics of a specific generator in relation to its incremental transmission network requirements, the Proposer undertook a significant amount of market modelling (as described above) using the NGET's Electricity Scenario Illustrator (ELSI) Model and a range of assumptions about background conditions based on reasonable forecasts of these conditions also used by NGET when planning transmission capacity. It was not the intention to use this type of modelling to generate produce actual TNUoS tariffs. Rather it was undertaken in an attempt to discover if a simple proxy for a generator's incremental impact on transmission network costs existed that could be incorporated into the existing ICRP approach. This would avoid the need for complex commercial arrangements to solicit more detailed information from generators, which was shown to be extremely difficult through the TAR industry process." (Final CUSC Modification Report Volume 2, Annexes, 4.20)

"Within this modelling, undertaken using ELSI, the Proposer [CMP213] concluded that a generator's annual load factor generally has a linear relationship with its impact on incremental constraint costs although the relationship may vary across different plant types and location due to the fact that the annual load factor is a manifestation of the relative economics of that generator; including its availability, fuel cost, efficiency, CO2 prices and subsidies such as ROCs." (Final CUSC Modification Report Volume 2, Annexes, 4.21)

"The blue diamond points on this plot represent the annual incremental cost impact of a generation plant type against its annual load factor as calculated by the ELSI model. The dotted green line represents the theoretically perfect relationship between annual load factor and annual incremental costs; whereas the red dashed line represents the theoretically perfect relationship between a generator's capacity (i.e. TEC) and annual incremental costs." (Final CUSC Modification Report Volume 2, Annexes, 4.23)

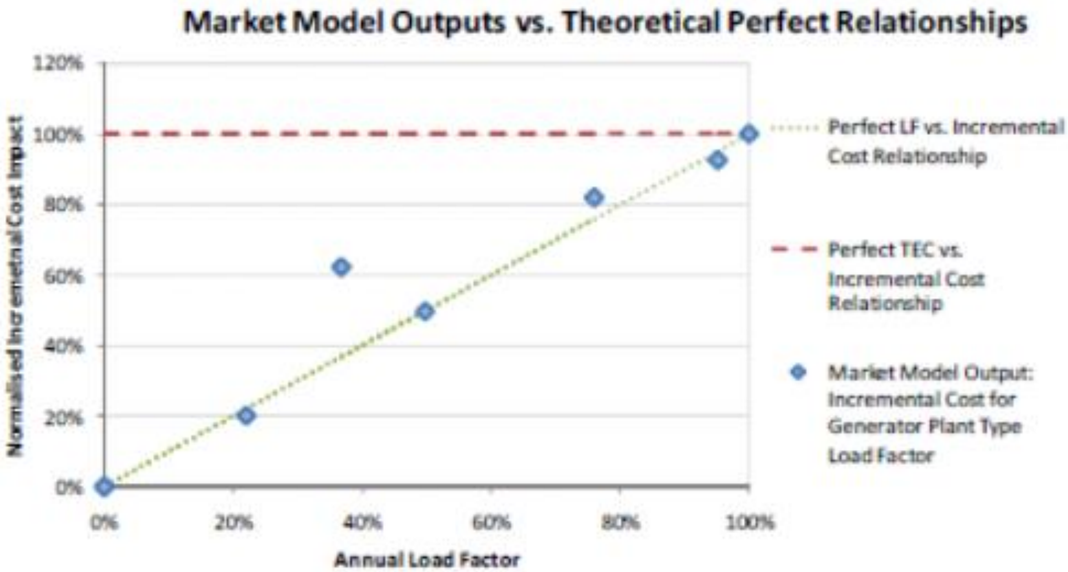


Figure 1 – Market Model Outputs vs. Theoretical Perfect Relationships

Figure 2 – Example ELSI analysis

2. Circumstances where sharing is reduced

The CMP213 Final Workgroup report goes on to explain the particular circumstances and causes regarding why network sharing may reduce so that it may become no longer appropriate to apply the ALF discount. This was described as occurring in zones with a relatively high proportion of Low Carbon generation for the following reason:

> " …**low carbon plant is more expensive to bid off than carbon plant, which generally has a lower bid price (close to marginal bid price), and is cheaper to constrain off**." (Final CMP213 Workgroup Report 4.21) [emphasis added]
>
> "The linear relationship between load factor and incremental constraint costs breaks down **when bids cannot be taken from plant at close to wholesale marginal price**, and are taken from low-carbon plant instead." (Final CUSC Modification Report Volume 1,4.22) [emphasis added]

The example below "…shows how in export constrained zones bid prices may become a significant factor in incremental constraint costs. The upward effect of high bid price is shown diagrammatically in Figure 5 below." (Final CUSC Modification Report Volume 1, 4.29)

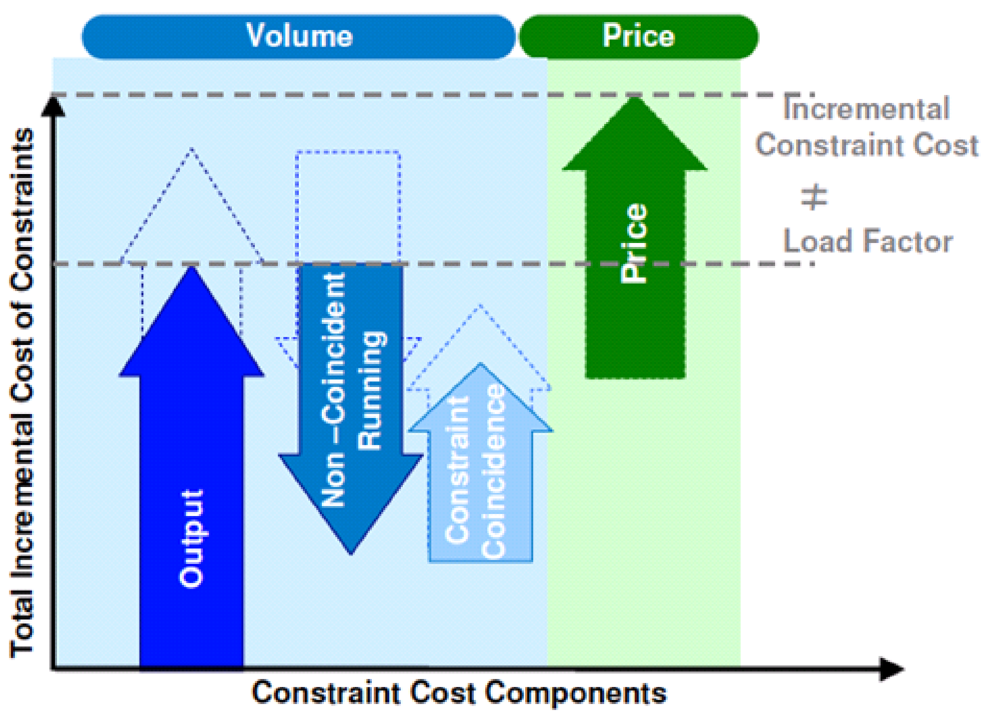


Figure 10 – Upward effect of high bid prices

Figure 8: taken from Figure 5 of the CMP213 Workgroup Final Report.

"It was further postulated by the modelling subgroup that the ideal network scenario is to build transmission network such that the low carbon plant is rarely constrained off, and a network of this size could absorb an equal volume of carbon plant. In such an idealised

> transmission network, **constraint action would only be required on carbon plant and this can be accessed at relatively low cost**. In any event, for significantly expensive actions (negative bid price) the general assumption is that, in areas where this type of plant is dominant, TOs would build transmission network capacity at or very close to the total generation capacity in the area concerned. Likewise, **where the costs of constraining plant off was relatively low, the general assumption is that the transmission network capacity would not be very close to the total generation capacity in the area concerned and this would, therefore, mean lower transmission network investment**" (Final CUSC Modification Report Volume 1, 4.36) [emphasis added]

The Workgroup carried out analysis of how the relationship between load factor and incremental constraint cost may break down in specific circumstances as shown in the graph below.

> "The Proposer [CMP213] noted that **the effect of bid and offer prices on incremental constraint costs is reflected in the market modelling undertaken** and shared with the Workgroup. Indeed the Workgroup noted that, where the relationship between incremental constraint costs and generation annual load factor was shown to deteriorate in future years, that this was largely in areas with increasing proportions of low carbon plant. Some members of the Workgroup noted that **this effect was due to the characteristics of low carbon plant, in particular their relatively high bid prices, driven by low fuel prices and volume related subsidies**." (Final CUSC Modification Report Volume 2, Annexes, 4.98) [emphasis added]

> "The Workgroup found that, where there was insufficient diversity of generation plant types behind a transmission network constraint, **the SO would no longer be able to accept bids from a generator close to price of the system marginal plant.** In this case the incremental cost of constraints would increase." (Final CUSC Modification Report Volume 2, Annexes 4.110) [emphasis added]

> "When the Workgroup delved deeper into the nature of this effect, it became clear that **the generation plant setting the bid price was the primary factor affecting the price of constraints**. Indeed, the Workgroup found that it was possible to broadly separate generating plant into two categories based on their bid prices". (Final CUSC Modification Report Volume 2, Annexes 4.111) [emphasis added]

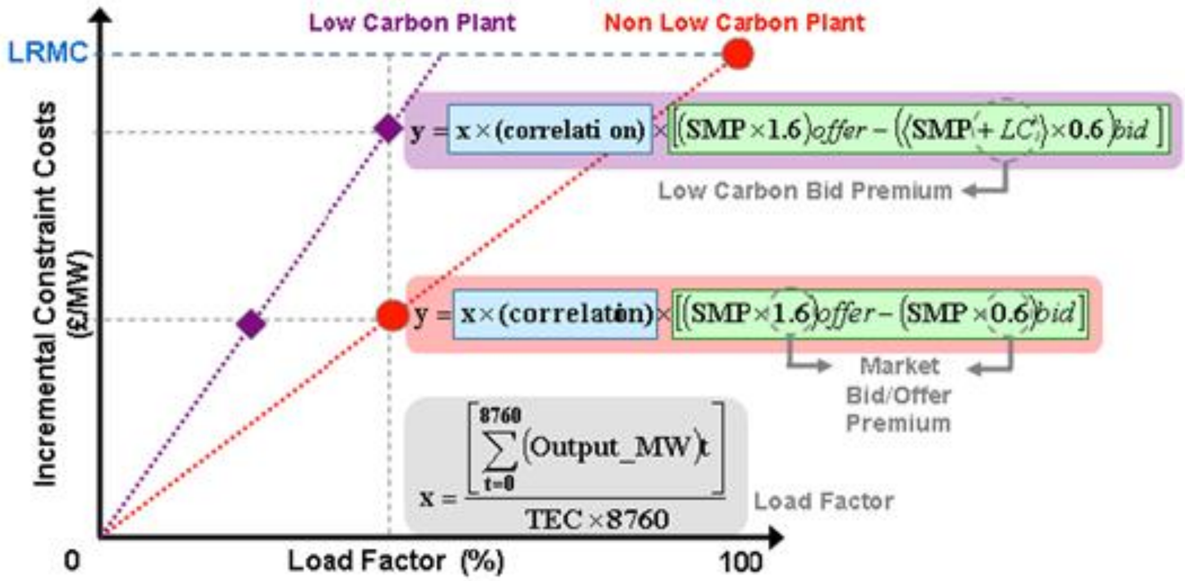


Figure 21 – Combined effect of price and load factor on constraint costs

"From the above the Workgroup appreciated that, **for areas of the transmission system with sufficient generation plant diversity** and a correlation of running and constraints fixed at that of the optimally invested transmission network level (i.e. at the point where incremental constraint costs are comparable to the incremental cost of capacity arising from the Transport model), **the incremental transmission network cost (shown in red above) is set by the annual load factor of the incremental 1MW of generation** (the volume element; shown in grey above) **and the bid price of the marginal non low carbon plant** (the price element; shown in green). The market bid/offer premium is assumed to be 0.6 and 1.6 times the short run marginal cost, which is the value used by the Proposer in the ELSI market model used to produce the generation annual load factor vs. incremental constraint cost graphs shared with the Workgroup. (Final CUSC Modification Report Volume 2, Annexes, 4.117) [emphasis added]

"Alternatively **for areas of the transmission system with insufficient generation plant diversity** and a correlation of running and constraints fixed at that of the optimally invested transmission network level, the incremental transmission network cost (shown in purple above) diverges such that for low carbon plant it is set by the annual load factor of the incremental 1MW of generation (the volume element; shown in grey above) and the bid price of the low carbon plant, which includes a low carbon bid premium - LC (the price element; shown in green). **In this instance the incremental transmission network cost for non-low carbon plant continues to be set by the factors in the grey and red boxes, as before**." (Final CUSC Modification Report Volume 2, Annexes,4.118) [emphasis added]

3. Evidence – Simplified two node model

The CMP213 Workgroup modelling subgroup carried out additional analysis using a simplified two node model with the conclusions below:

"As we see in Figure 7, where bid and offer prices are taken from marginal plant types, there is a linear relationship between load factor and incremental constraint costs. The impact of different categories of plant on this relationship is explored in Figure 12 below. The red dotted line shows the ideal linear relationship. Mapped against this are the impact of low carbon and carbon generation on this relationship as the percentage of low carbon generation in a zone increases. As the percentage of low carbon plant increases above 50% the cost of bids significantly increases. **It follows in these circumstances that incremental low carbon plant increases constraint costs whilst incremental carbon plant reduces incremental constraint costs**. This latter effect is because the volume of low carbon plant that runs provides cheaper bids than previously available in that transmission charging zone; i.e. the slope in that zone was previously steeper." (Final CUSC Modification Report Volume 1, 4.38) [emphasis added]

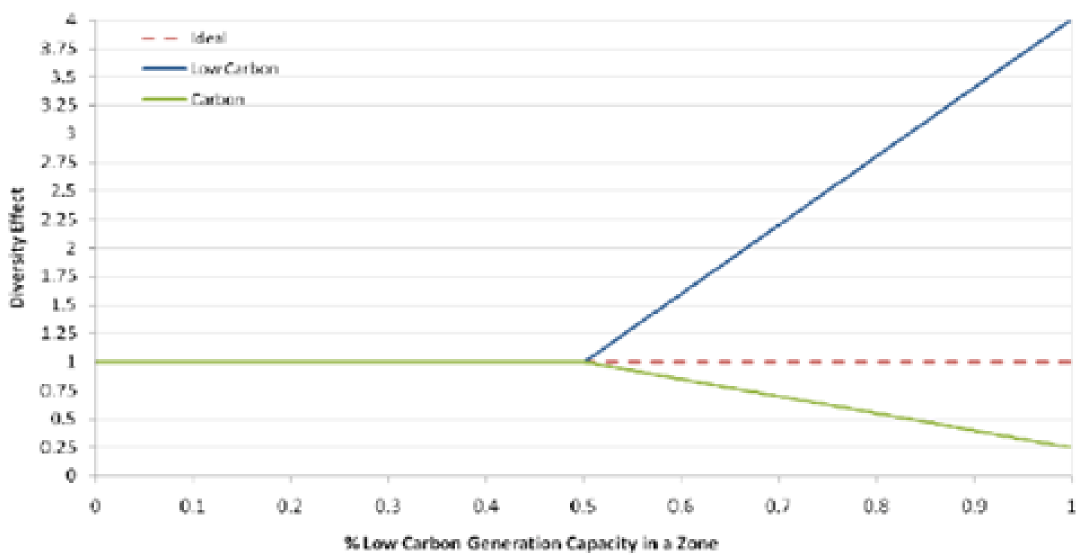


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

4. Evidence – ELSI Market Model

The CMP213 Proposer carried out analysis using the market modelling tool ELSI. A snapshot of this analysis is provided in the CMP213 Final Workgroup Annex 2 as per below.

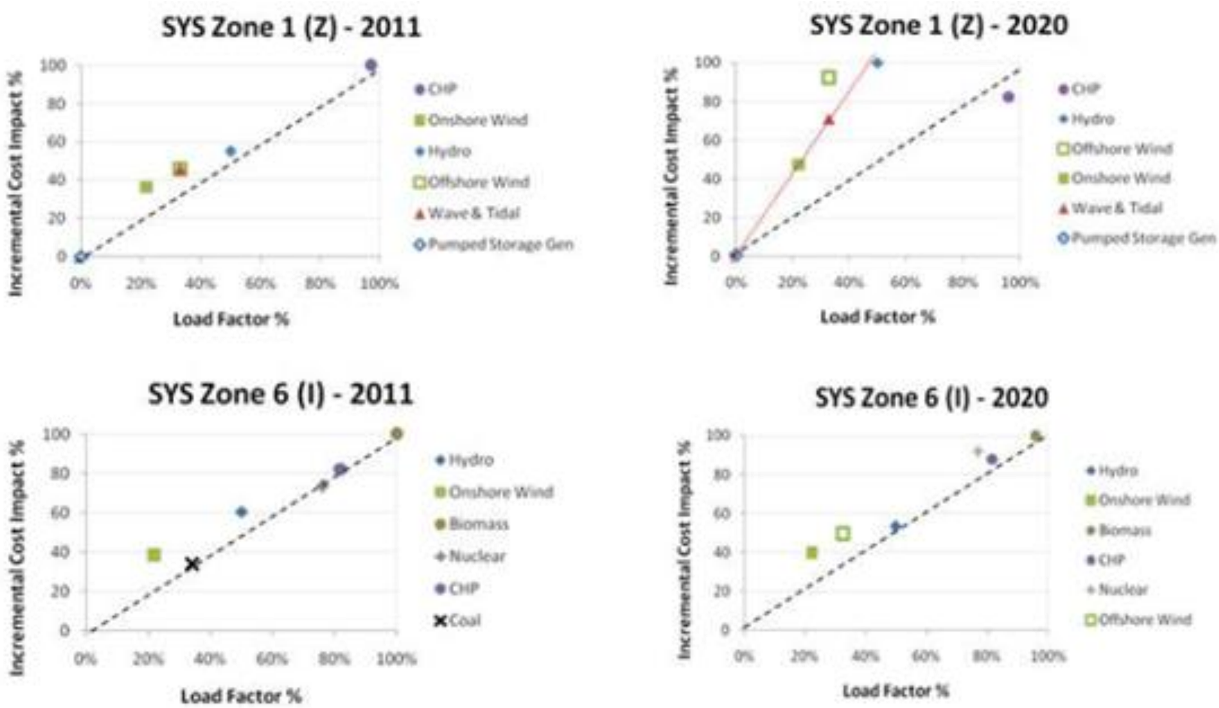


Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

“The approach of Method 1 is to build upon the existing market modelling undertaken in ELSI which some Workgroup members agreed demonstrated that a relationship between the annual load factor of an individual generating plant and its impact on incremental transmission network costs exists, and the subsequent investigation by the Workgroup concluding that in areas of the transmission network with insufficient diversity of generation plant, **the high bid prices of low carbon generators leads to a divergence of this relationship as set out in paragraphs 4.101 through to 4.121** The aforementioned divergence is consistent with the ELSI based analysis undertaken by the Proposer that demonstrated a deterioration of the generation annual load factor vs. incremental constraint cost relationship in the long term in areas of the transmission system with insufficient diversity of generation plant. A snapshot of this analysis shared with the Workgroup is shown in Figure 21 below. These graphs show that in SYS Zone 1 the relationship breaks down as large proportions of low carbon generators are assumed to connect by 2020 (using NGET’s Gone Green scenario), but that in SYS Zone 6 the relationship remains reasonably robust due to the diversity of plant behind the relevant transmission boundary.” (Final CUSC Modification Report Volume 2, Annexes, 4.135) [emphasis added]

5. Evidence Cost reflectivity compared with SQSS

P E Baker published a report procured by SSE which carried out a comparison of [CMP213] WACM2 and Status Quo zonal charges in how they differ from costs implied by the SQSS.[1]

> "In order to compare the cost-reflectivity of the Status Quo and CMP213-WACM2 charging methodologies, the tariff elements given in NGET's "Initial view of 2015/16 TNUoS tariffs" were used to compute CMP213-WACM2 charges for wind, nuclear, conventional and peaking generation for each of the 27 charging zones. These, together with the existing TNUoS methodology charges, were then compared with the costs incurred by the TOs computed by application of the pseudo-CBA SQSS methodology. In computing these costs, the scaling factors from NGET's ICRP draft sharing model shown in Table 1 were used." (Baker March 2014, 4)

Plant Type	TEC	Generation - Peak Security	Generation - Year Round	Peak Security Generation	Generic LF Generation
Conventional	61,386	73%	66%	100%	75%
Intermittent	5,378	0%	70%	0%	25%
Peaking	5,455	73%	0%	100%	1%
Pumped Storage	2,744	73%	50%	100%	30%
Nuclear & CCS	10,841	73%	85%	100%	60%
Interconnectors	3,268	0%	100%	0%	0%

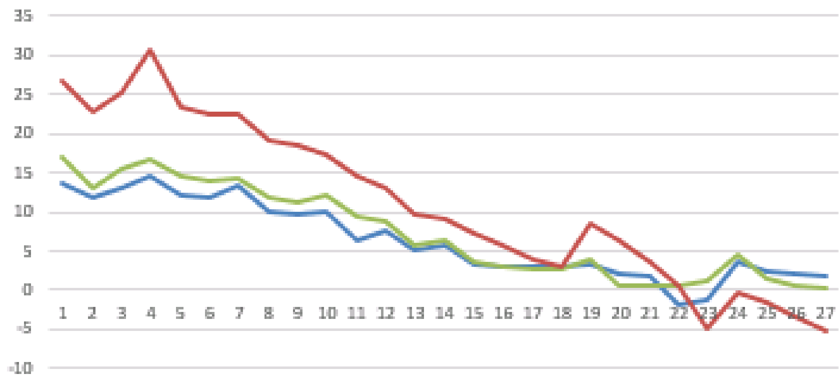
Table 1. Generating technology scaling factors

Table 1: Taken from Table 1 (Baker March 2014, 4)

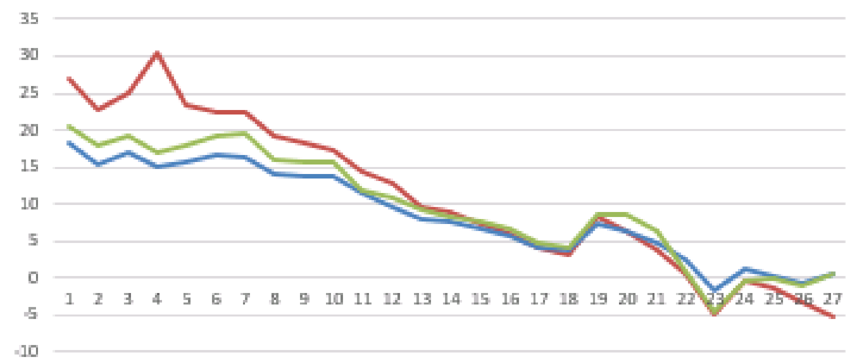
> "The outcome of this analysis is set out in Figure 2, which shows the charges for each generation technology and how these compare with the costs implied by the SQSS. It can be seen that combining the peak security, Year-Round and residual components produced by the CMP213-WACM2 methodology result in charges that are closer to the costs suggested by the application of the SQSS criteria than the Status Quo for almost all of the charging zones. While, as discussed in Section 3.1, the SQSS criteria represent a proxy for of the real-world identification of transmission investment requirements and do not determine the actual costs incurred by TOs, it is worthy of note that CMP213-WACM2 delivers an outcome far closer to the "short hand" methodology of determining SQSS costs than does the Status Quo in almost all circumstances." (Baker March 2014, 4)

[1] Review for SSE of Poyry's Report to Centrica Energy "Review of Ofgem's Impact Assessment on CMP213, P E Baker, March 2014. https://www.ofgem.gov.uk/sites/default/files/docs/2014/04/review_for_sse_of_poyrys_report_to_centrica_energy_titled_review_of_ofgems_impact_assessment_on_cmp213_0.pdf

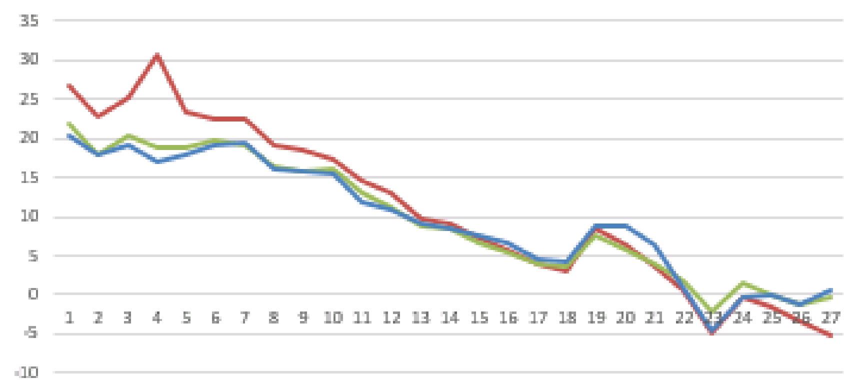
Wind (£/kW)



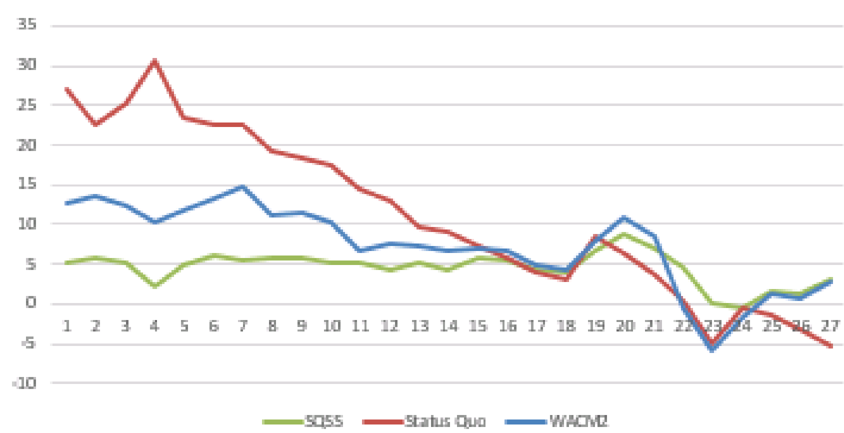
Conventional (£/kW)



Nuclear (£/kW)



Peaking (£/kW)



6. Evidence - Alternative modelling of cost reflectivity

P E Baker carried out additional energy system analysis which is described in further detail in section 5 of the Baker March 2014 report.

> "In order to further investigate the cost-reflectivity of the CMP213-WACM2 charging methodology, the simple 2-bus single circuit model shown in Figure 1 is applied to situations where the dominant power flows occur in the Peak Security background and for different degrees of sharing in situations where the dominant flows occur in the Year-Round background."

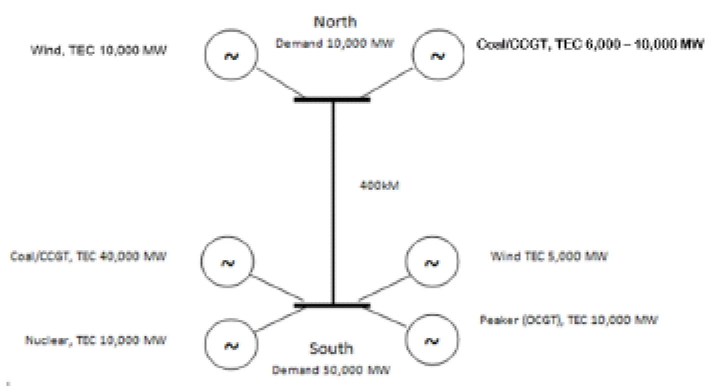


Figure 3, Simple 2 bus representation of GB system

Figure 10: Taken from Figure 3 from P E Baker analysis

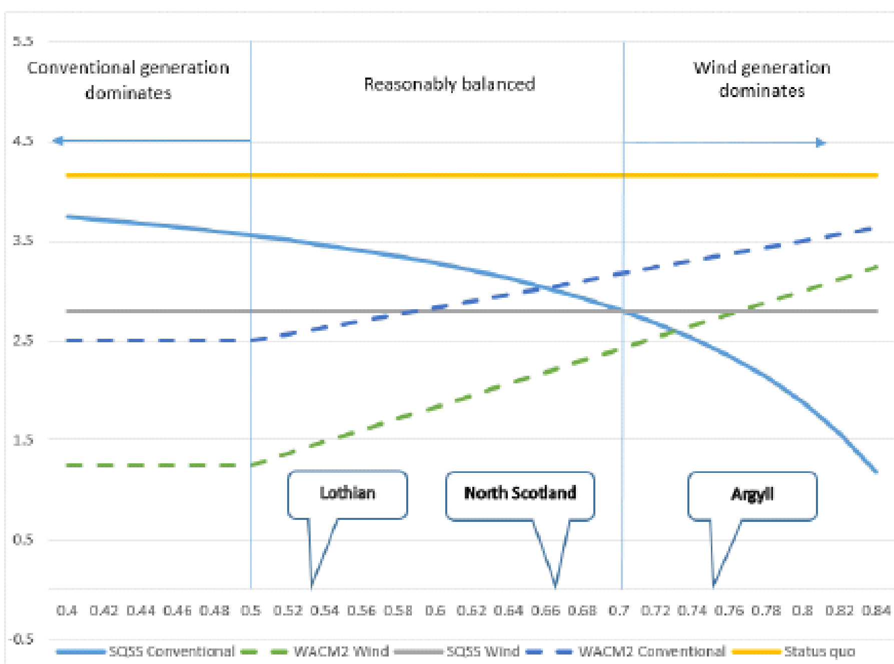


Figure 4. Variation of SQSS costs (£/kW) and WACM2 & Status Quo charges (£/kW) with sharing

“Again, it can be seen from Figure 4 that the **CMP213-WACM2 charges for both wind and conventional generation increase with increasing wind capacity, as the non-shared element of the methodology becomes increasingly influential.** **Charges for conventional generation exceed SQSS costs, which decline as wind becomes increasingly dominant.** Charges for wind also rise above SQSS costs as wind capacity increases. **Both wind and conventional charges converge and would equal the Status Quo charge in situations where only wind generation is present**.” (Baker March 2014 5.2.3[typo in original report referenced this as 4.2.3]) [emphasis added]

“**The fact that conventional generation should increasingly be able to utilise network capacity necessary to accommodate wind as the dominance of wind increases is not recognised by either the Status Quo or the CMP213-WACM2 methodology**.” (Baker March 2014 5.2.3 [typo in original report referenced this as 4.2.3]) [emphasis added]

“The charges incurred under CMP213-WACM2 and the Status Quo are summarised in Table 2, together with the costs arising from applying the pseudo-CBA SQSS methodology. It can be seen that the CMP213-WACM2 methodology produces charges that are consistent with the costs and notional savings incurred by the TO in applying SQSS criteria. **The connection of conventional plant to the Northern node, necessary to support local demand in the event of transmission failure, would be encouraged through a negative charge. Conversely, the existing TNUoS charging methodology [pre CMP213 Status Quo] gives a perverse and potentially dangerous signal, discouraging the connection of generation to the Northern node even though that generation would contribute to the security of the local system under peak demand conditions when wind output is likely to be low**. Generation connected to the Sothern node also experience charges under the existing TNUoS charging regime [pre CMP213 Status Quo] that have the opposite sign to the costs suggested by the SQSS.” (Baker 5.1). [emphasis added]

7. Evidence - From NERA/ICL for RWE – Cost reflectivity Vs LRMC

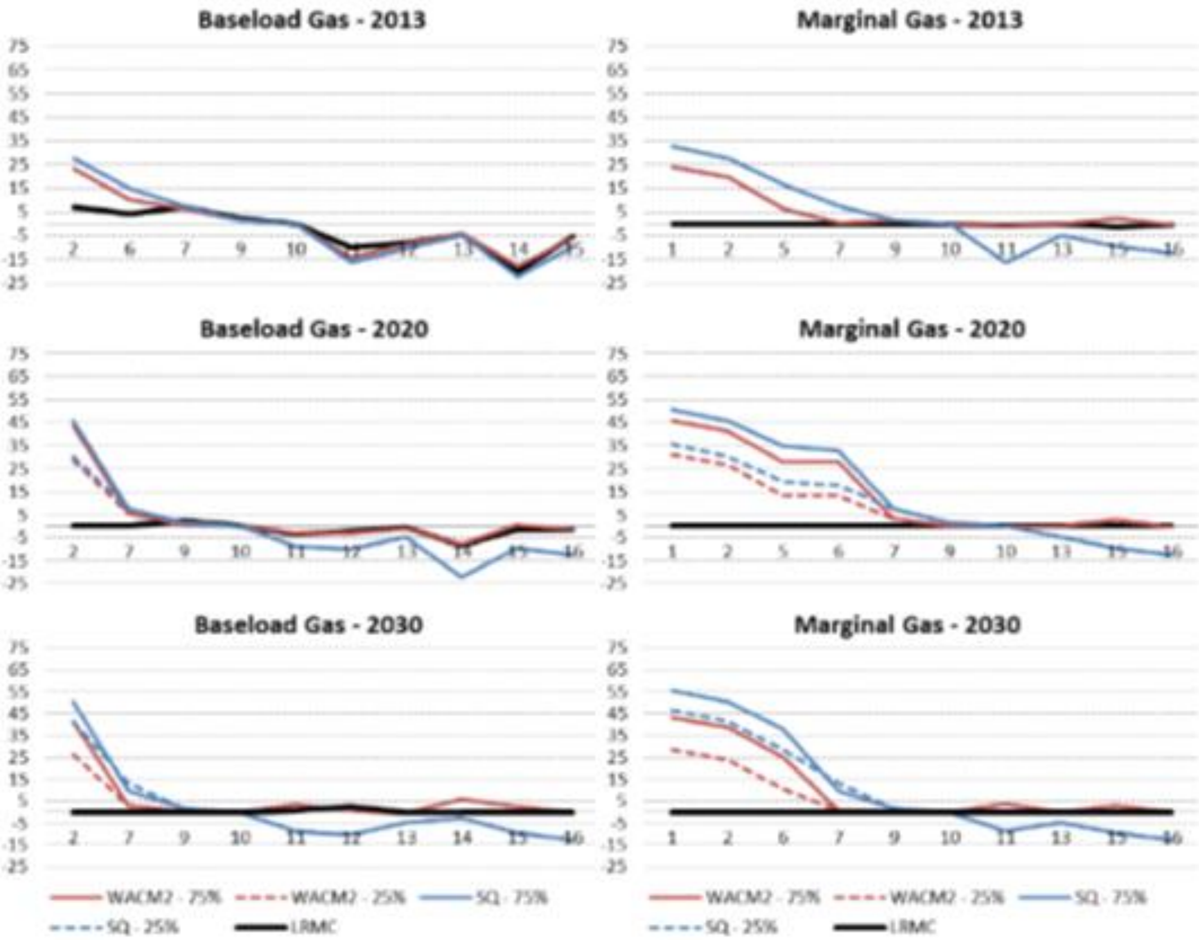
RWE procured analysis from NERA/ICL, Assessing the Cost Reflectivity of Alternative TNUoS Methodologies (February 2014)2 which compared the TNUoS tariffs derived from the pre April 2016 Status Quo charging methodology and those provided by the CMP213 WACM2 methodology with an analysis of Long Run Marginal Cost (LRMC) caused by different types of generating station.

> "**<u>As noted above, LRMCs for peaking gas-fired generators are low in all zones, often close to zero. Both the WACM 2 and status quo methodologies charge this type of generator tariffs well-above LRMC in the Scottish zones in 2013, 2020 and 2030</u>**. WACM 2 tariffs for this type of generator tend to be lower in Scotland, and so are marginally closer to LRMC. In other words, **<u>both status quo and WACM 2 exaggerate the locational signal conveyed through TNUoS as compared to LRMC.</u>** Because the WACM 2 charging methodology reduces the locational spread in tariffs, it produces tariffs that are closer to LRMC" (NERA/ICL 5.2.2.) [emphasis added]

> "**<u>WACM 2 and the status quo methodologies set locational tariffs to peaking plants in Scotland in excess of the LRMC of transmission that their presence imposes on the system relative to the LRMC of connecting in other parts of the country</u>**. Because WACM 2 compresses the spread between tariffs in the north and tariffs in the south more than the status quo, this suggests that WACM 2 is more cost reflective for this category of generation. However, under both WACM 2 and status quo methodologies, TNUoS charges are lower for peaking plants in England and Wales than in Scotland. Hence, setting TNUoS for peaking plants in Scotland that are above the efficient level is unlikely to change locational decisions materially, and thus will have no impact on transmission system costs." (NERA/ICL 5.4) [emphasis added]

[2] http://www.nera.com/content/dam/nera/publications/2014/CostReflectivityReport.pdf

Figure 5.4
TNUoS vs. LRMC for Gas Capacity (£/kW/yr, by DTIM Zone)



Source: NERA/Imperial

8. Evidence from Poyry for Centrica

The proposer presented an extract from a report produced by Poyry[3] regarding specific circumstances where CMP213 may provide a perverse price signal which could put regional security of supply at risk. The proposer presented the quote from Poyry as follows:

> "Consider a two zone system, there the smaller zone, A consists almost entirely of wind capacity – say 9.5GW of wind and 0.5GW of inefficient OCGT (a small bit of nuclear/hydro/pumped storage doesn't change this example much). Under Diversity 1, there would be almost no sharing assumed, and the zone would be an importer for the peak component, so have a negative peak charge. However, **with almost no sharing an OCGT would pay nearly as much for the year round as the wind (or indeed a nuclear plant if there was one). However, the OCGT wouldn't run in practice unless the wind output was low – consequently it is very unfair that it should have to pay high year-round charges**. Indeed, in this example zone A would be a very good location for an OCGT (as the negative peak charge would signify a strong need for generation capacity). **Whilst this may or may not offset the inappropriate year round tariff – the key point is that for a high wind zone the CMP213 year round tariff is not cost reflective and over-allocates cost to the non-wind generation in the zone.** (Poyry 3.2.1.4) [emphasis added]

[3] https://www.ofgem.gov.uk/ofgem-publications/85135/consultationresponsefromcentrica2.pdf

Annex 8 – Draft Legal text

CMP268 LEGAL TEXT – with explanation

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

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

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

a.

Where

$ITRR_G$ = Initial Transport Revenue Recovery for generation

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

$ITRR_D$ = Initial Transport Revenue Recovery for demand

D_{Di} = Total forecast Metered Triad Demand for each demand zone (based on confidential User forecasts)

In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. ~~Similarly, when~~ When calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below). When calculating the initial revenue recovery for the Not Shared component of the Year Round background, the initial tariffs are multiplied by the **Year Round Not Shared Flag**.

Peak Security (PS) Flag

14.15.99 The revenue from a specific generator due to the Peak Security locational tariff needs to be multiplied by the appropriate Peak Security (PS) flag. The PS flags indicate the extent to which a generation plant type contributes to the need for transmission network investment at peak demand conditions. The PS flag is derived from the contribution of differing generation sources to the demand security criterion as described in the Security Standard. In the event of a significant change to the demand security assumptions in the Security Standard, National Grid will review the use of the PS flag.

Generation Plant Type	PS flag
Intermittent	0
Other	1

Year Round Not Shared (YRNS) Flag

Comment [NG1]: New paragraph added to explain Conventional carbon. For the non conventional carbon the YRNS is multiplied by 1 as they pay the full amount. For conventional carbon this is multiplied by the ALF

14.15.100 The revenue from a specific generator due to the Year Round Not Shared locational tariff needs to be multiplied by the appropriate Year Round Not Shared (YRNS) flag. The YRNS flag indicates the extent to which a generation plant type contributes to the need for transmission network investment at year round demand conditions in areas of the System where the proportion of Low Carbon generation exceeds Carbon generation as defined in 14.15.49.

Generation Plant Type	YRNS flag
Non Conventional Carbon	1
Conventional Carbon	ALF

Initial Revenue Recovery

14.15.113 For the Peak Security background the initial tariff for generation is multiplied by the total forecast generation capacity and the PS flag to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,PS} \times G_{Gi} \times F_{PS}\right) = ITRR_{GPS}$$

Where

$ITRR_{GPS}$ = Peak Security Initial Transport Revenue Recovery for generation

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

F_{PS} = Peak Security flag appropriate to that generator type

n = Number of generation zones

The initial revenue recovery for demand for the Peak Security background is calculated by multiplying the initial tariff by the total forecast metered triad demand:

$$\sum_{Di=1}^{14}\left(ITT_{DiPS} \times D_{Di}\right) = ITRR_{DPS}$$

Where:

$ITRR_{DPS}$ = Peak Security Initial Transport Revenue Recovery for demand

D_{Di} = Total forecast Metered Triad Demand for each demand zone (based on confidential User forecasts)

14.15.114 For the Year Round background, the initial tariff for generation is multiplied by the total forecast generation capacity whilst calculating Initial Recovery for the Not-Shared component from Non Conventional Carbon. For Conventional Carbon the initial tariff for the Not Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery. ~~whereas T~~the initial tariff for the Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNSNCC} \times G_{Gi}\right) = ITRR_{GYRNSNCC}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNSCC}\ x\ G_{Gi}\ x\ ALF\right) = ITRR_{GYRNSCC}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS} \times G_{Gi} \times ALF\right) = ITRR_{GYRS}$$

$$ITRR_{GYRNS} = ITRR_{GYRNSNCC} + ITRR_{GYRNSCC}$$

Where:

$ITRR_{GYRNSNCC}$ = Year Round Not-Shared Initial Transport Revenue Recovery for Non Conventional Carbon generation

$ITRR_{GYRNSCC}$ = Year Round Not-Shared Initial Transport Revenue Recovery for Conventional Carbon generation

$ITRR_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

$ITRR_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

ALF = Annual Load Factor appropriate to that generator.

14.15.97 The factors which will affect the level of TNUoS charges from year to year include-;

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Comment [NG2]: Created new term for conventional carbon and adjusted the original one. Revenue recovery for Year Round Not Shared now needs to be split up into two

Comment [NG3]: Adding this term to solve having to change later equations which refer to the original ITRR_GYRNS term 14.15.132 and 14.15.133

(

- the forecast level of peak demand on the system
- the Price Control formula (including the effect of any under/over recovery from the previous year),
- the expansion constant,
- the locational security factor,
- the PS flag
- the Year Round Not Shared (YRNS) Flag
- the ALF of a generator
- changes in the transmission network
- HVDC circuit impedance calculation
- changes in the pattern of generation capacity and demand.

Comment [NG4]: New Flag to reflect the YRNS

Structure of Generation Charges

14.18.1 Generation Tariffs are comprised of Wider and Local Tariffs. The Wider Tariff is comprised of (i) a Peak Security element, (ii) a Year Round Not-Shared element, (iii) Year Round Shared element and (iv) a residual element. The Peak Security element of the Wider Tariff is not applicable for intermittent generators as the PS flag is set to zero. The Year Round Not Shared element is multiplied by the YRNS Flag, which for Non-Conventional Carbon Generators rsults in no change to the tariff, whereas for Conventional Carbon generators the tariff is reduced by ALF

Comment [NG5]: Added to explain how Year Round Not Shared

14.18.7 If there is a single set of Wider and Local generation tariffs within a charging year, the Chargeable Capacity is multiplied by the relevant generation tariff to calculate the annual liability of a generator.

$$Local\ Annual\ Liability = Chargeable\ Capacity \times Local\ Tariff$$

The Wider Tariff is broken down into four components as described in 14.18.3. The breakdown of the Wider Charge for Conventional and Intermittent Power Stations are given below:

Conventional –

$$Wider\ Annual\ Liability = Chargeable\ Capacity \times (PS\ Tariff + YRNS\ Tariff + (YRS\ Tariff \times ALF) + Residual Tariff)$$

Conventional Carbon

Comment [NG6]: New term. Needs to be added for the new class of conventional carbon

$$Wider\ Annual\ Liabiity\ Chargeable\ Capacity\ x\ (PS\ Tariff + (YRNS\ Tariff\ x\ ALF) + (YRS\ Tariff\ x\ ALF) + Residual\ Tariff$$

Intermittent -

$$Wider\ Annual\ Liability = Chargeable\ Capacity \times (YRNS\ Tariff + (YRS\ Tariff \times ALF) + Residual Tariff)$$

Where:
PS Tariff = Wider Peak Security Tariff
YRNS Tariff = Wider Year Round Not-Shared Tariff
YRS Tariff = Wider Year Round Shared Tariff

CMP268 LEGAL TEXT – Clean version

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

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In addition, the initial tariffs for generation are also multiplied by the **Peak Security flag** when calculating the initial revenue recovery component for the Peak Security background. When calculating the initial revenue recovery for the Shared component of the Year Round background, the initial tariffs are multiplied by the **Annual Load Factor** (see below). When calculating the initial revenue recovery for the Not Shared component of the Year Round background, the initial tariffs are multiplied by the **Year Round Not Shared Flag**.

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$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNSNCC}\times G_{Gi}\right)=ITRR_{GYRNSNCC}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRNSCC}\ x\ G_{Gi}\ x\ ALF\right)=ITRR_{GYRNSCC}$$

$$\sum_{Gi=1}^{n}\left(ITT_{GiYRS}\times G_{Gi}\times ALF\right)=ITRR_{GYRS}$$

$$ITRR_{GYRNS}=ITRR_{GYRNSNCC}+ITRR_{GYRNSCC}$$

Where:

ITRR$_{GYRNSNCC}$ = Year Round Not-Shared Initial Transport Revenue Recovery for Non Conventional Carbon generation

ITRR$_{GYRNSCC}$ = Year Round Not-Shared Initial Transport Revenue Recovery for Conventional Carbon generation

ITRR$_{GYRNS}$ = Year Round Not-Shared Initial Transport Revenue Recovery for generation

ITRR$_{GYRS}$ = Year Round Shared Initial Transport Revenue Recovery for generation

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Conventional Carbon

$$Wider\ Annual\ Liabiity\ Chargeable\ Capacity\ x\ (PS\ Tariff + (YRNS\ Tariff\ x\ ALF) + (YRS\ Tariff\ x\ ALF) + Residual\ Tariff$$

Intermittent -

$$Wider\ Annual\ Liability\ = Ch\arg eable\ Capacity \times (\ YRNS\ Tariff + (YRS\ Tariff \times ALF) + \mathrm{Re}\, sidual Tariff\ )$$

Where:
PS Tariff = Wider Peak Security Tariff
YRNS Tariff = Wider Year Round Not-Shared Tariff
YRS Tariff = Wider Year Round Shared Tariff