nationalgrid

Stage 02:– Workgroup Report Following Authority Send Back

Connection and Use of System Code (CUSC)

CMP268‘Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits’ Report 2

What stage is this document at?

02	Send back Workgroup Report
03	Code Administrator Consultation
04	Final 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 findings of the Workgroup following the Authority send back dated 2nd December 2016. Please ensure you read this in conjunction with the initial Report submitted to the Authority. This is attached to the back of this send back submission.

The initial Report submitted to Ofgem in November 2016 can be found at the following link: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/

High Impact:
Generation TNUoS payers

Medium Impact:
Name of parties impacted or None identified

Low Impact:
Name of parties impacted or None identified

Contents

Any Questions?

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About this document

This document is a Workgroup Report which contains the discussions of the Workgroup following the Authority send back dated 2nd December 2016.

Document Control

Version	Date	Author	Change Reference
0.1	16/06/2017	Workgroup	Workgroup Report to be issued to CUSC Panel

1 Summary

Authority Send back

1.1 On the 2nd December 2016 the Authority made the decision to send back CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits' the letter stated the following:

> "We consider that the workgroup should be reconvened to further consider the evidence submitted so far and to consider whether any further evidence is required to allow the Panel and us to properly consider the merits of the proposal.
> The FMR should consider in more depth the potential impacts of the proposed solution, as compared to retaining the current system. The workgroup should consider whether further consultation on the proposals and evidence is appropriate (following completion of steps 1. and 2.)"

1.2 The Final Modification Report that was sent to the Authority on the 8th November 2016 can be found at the following link along with the Send Back letter:http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/

1.3 Following the discussions that the Workgroup had following the Authority send back decision the Proposer requested to vary their solution. However, the CUSC Panel judged that this variation was not permitted within the CUSC "send back" regulations, so the Original proposed solution remained unchanged. The proposer remains in full support of the Original proposal as being clearly and substantially better than Baseline, particularly from the point of view of better cost reflectivity and better facilitating effective competition.

Workgroup Conclusions following send back

1.4 As there were no alternatives raised and the Proposer did not amend their original proposed solution a further Workgroup Consultation and vote was not carried out.

1.5 The discussions and information within this Report need to be read in conjunction with the original Final Modification Report that was submitted to the Authority in November 2016.

2 Evidence & Analysis

2.1 Introduction

2.1.1 The Workgroup noted that the Authority asked the Workgroup to undertake the following:

"*We consider that the workgroup should be reconvened to further consider the evidence submitted so far and to consider whether any further evidence is required to allow the Panel and us to properly consider the merits of the proposal*" (Ofgem send back letter dated December 2016).

2.2 This section describes how the Workgroup has met this Authority direction regarding evidence. This summarises the evidence provided to the Workgroup by National Grid, summary of Workgroup discussions regarding this evidence and also a description of further consideration by the Workgroup of previous evidence which had been submitted prior to send back.

The Workgroup discussion is summarised in this section, while a more detailed description of the reasoning can be found in Annex 1.

This summary comprises of the following parts:

- National Grid Representative from CMP213 overview of analysis discussed during CMP213
- Additional discussion of the CMP213 analysis regarding incremental costs
- New modelling analysis provided by the National Grid Economics Team
- Additional presentation of NERA/ICL evidence provided as part of CMP213
- Issue of constrained running

2.3 Workgroup consideration of CMP213 Analysis. Presentation provided by National Grid representative from CMP213

2.3.1 A National Grid Representative from the CMP213 workgroup provided a presentation to the workgroup setting out the rationale behind the Year Round Shared and Year Round Not Shared elements of the tariffs as discussed during CMP213 (see Annex 2). The aim of this presentation was to explain how the baseline was derived.

2.3.2 In the workgroup discussion on the CMP213 presentation, some workgroup members saw the analysis supporting the move from a Year Round tariff to a Year Round Shared / Year Round Not Shared tariff as a key starting point to CMP268.

2.3.3 The CMP213 workgroup noted that the original CMP213 proposal suggested that there was a linear relationship between constraint costs and load factor. Therefore it was proposed that the year round tariff should be subject to an adjustment based on an Annual Load Factor (ALF).

2.3.4 However analysis undertaken by the CMP213 workgroup suggested that there was a divergence between load factor and constraint costs in zones dominated by low carbon generation. This is illustrated in Figure 1. Please note that CHP was defined as the perfectly correlated relationship but only in terms of setting the baseline which all other technology types were compared against.

Annual load factor vs. annual incremental cost

2.4 Figure 1 from the CMP213 analysis below shows the result from National Grid ELSI modelling. Some workgroup members questioned the National Grid Representative from CMP213 to check their interpretation of the graph. Interpretation: *This analysis showed that in an area dominated by wind (SYS Zone 1 2020), the incremental cost impact of plant classed as Conventional Carbon (Pumped Storage Generation and CHP) remains proportional to their ALF as shown by their location on the black dotted 45 degree line. By contrast, it is only plant classed as Low Carbon (onshore wind, offshore wind, wave & tidal and hydro) which exhibit an incremental cost impact which is greater than that reflected by their ALF as reflected by their location on the steeper red line (Sys Zone 1 2020).* The National Grid Representative agreed that the graph could be interpreted in that way and was at the time by some workgroup members, but conceded that other workgroup members during CMP213 had differing views. It must be noted that some workgroup members during CMP268 disagreed with the above interpretation, for example it assumes all CHP plant has the same costs and drivers.

Figure 1: Graph from the CMP213 Presentation that illustrate the differing relationships between load factor and incremental costs

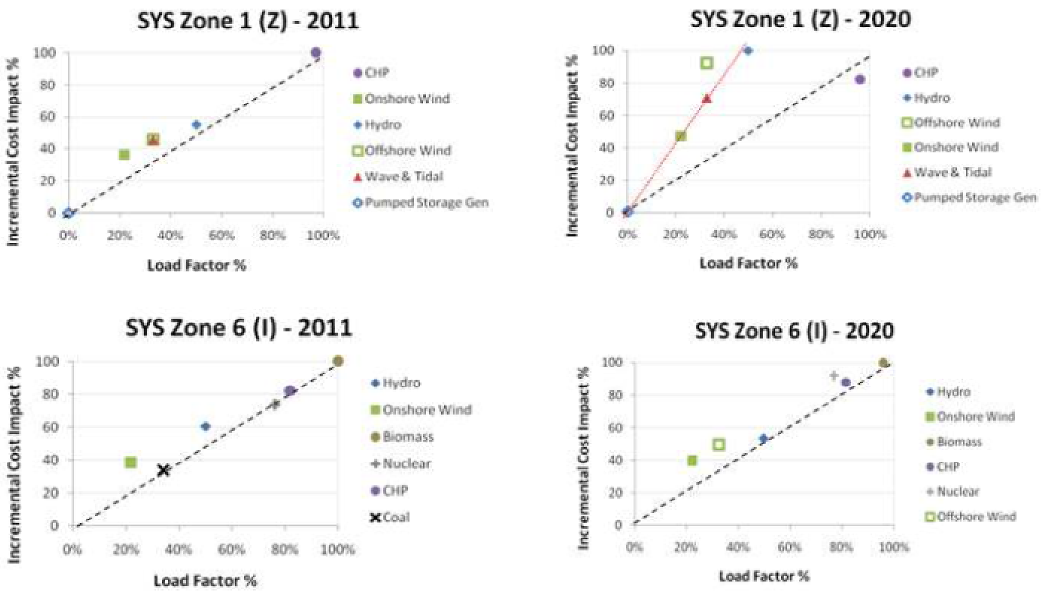
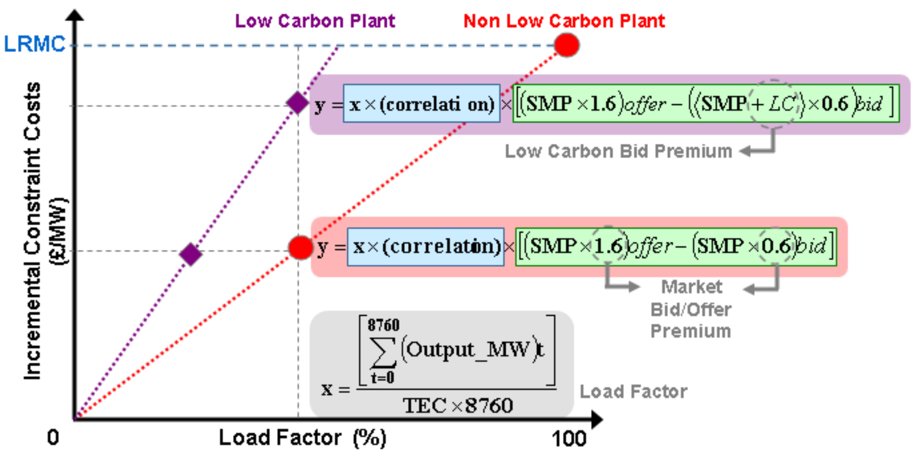


Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

2.5 Under the current Baseline all Generation is charged based on TEC in Low Diversity zones. Some workgroup members argued that what figure 1 illustrates is that the perfectly correlated relationship between Load Factor and Constraint costs as shown in Sys Zones for 2011 diverges away from the perfectly correlated relationship for Low Carbon Generation and not Conventional Carbon. This is seen as key rationale for the proposed solution for CMP268. However some workgroup members stated that moving to this solution assumed that all other assumptions regarding Sharing i.e. the Baseline, were correct, which they did not necessarily agree with.

Bringing together observations and theory

Figure 2: Graph from the CMP213 Presentation that illustrates the higher costs of bid prices for low carbon plant



The National Grid CMP213 representative went on to explain in detail the relationship between Load Factor and constraint costs from a CMP213 perspective and then suggested why it broke down in zones with Low Diversity of Generation.

2.6 The CMP213 Workgroup considered the economic drivers of this relationship, which is illustrated in figure 3 on page 7. The evidence provided during the CMP213 Workgroup process explained an economic reasoning why incremental cost is initially proportional to ALF when the concentration of Low Carbon generation is low, and then why the incremental cost caused by different types of generation diverges from a correlation of 1 when there is a higher concentration of Low Carbon generation.

2.7 The National Grid Representative from the CMP213 Workgroup explained that the CMP213 workgroup concluded that zones dominated by low carbon generation (low “diversity” zones) are likely to drive (proportionally) greater investment in transmission assets than zones with a higher diversity of Generation due to higher incremental constraint costs. The CMP213 Workgroup suggested therefore that it was not appropriate to charge all generation based on ALF in zones of dominated by low carbon generation (Year Round Not Shared).

2.8 The National Grid Representative from CMP213 Workgroup explained that with reference to the modelling undertaken during CMP213 that when there is a low concentration of Low Carbon generation, the marginal bid price required by the System Operator will tend to be that of a plant classed as Carbon and in these particular circumstances, the incremental cost caused by all types of generator (both Low Carbon as well as Carbon) is driven by the same function as each other and this is appropriately reflected as being proportional to their ALF. This is illustrated by the red dotted line in figure 2.

2.9 The National Grid Representative from CMP213 Workgroup stated that as the concentration of Low Carbon plant increases, the divergence in cost occurs because the cost caused by Low Carbon generation increases to become a function of the relatively more expensive Low Carbon bid prices instead (as represented by the "Low Carbon bid premium" in the figure 2), therefore the cost caused by Low Carbon plant increases to be greater than that reflected by their ALF.

2.10 The National Grid Representative from CMP213 Workgroup further explained how this part of the CMP213 evidence explained the economic principles regarding why, even when the concentration of Low Carbon generation is high, the incremental cost caused by plant classed as Carbon does not increase to become any greater than the relatively low cost of a Carbon plant bid price, so the cost by this type of plant does not increase to become any greater than that reflected by their ALF. This is illustrated by the red dotted line in figure 2.

It must be noted that paragraphs 2.8 to 2.11 explains the rationale and conclusions behind the final accepted proposal for CMP213. However not all CMP213 workgroup members as well as CMP268 workgroup members agreed with the analysis and conclusions.

2.11 The CMP268 Workgroup discussed in detail why the relationship between Load Factor and constraint costs broke down in zones with Low Diversity of Generation.

2.12 The evidence according to some workgroup members explains the economic rationale regarding why the divergence in incremental constraint cost caused by Low Carbon compared with Carbon takes place. This is because when the concentration of Low Carbon generation increases, then the incremental cost caused by Low Carbon generation increases to be that reflected by the higher purple line, while the incremental cost caused by Carbon plant does not increase to be any greater than that reflected by the red dotted line.

2.13 Some workgroup members stated that the evidence provided for CMP213 also explains why Carbon and Low Carbon generation should be proportionally charged differently and this forms the basis of the defect identified by CMP268. Baseline applies the YRNS tariff at 100% of TEC in the same way for both Low Carbon and Carbon plant. However CMP268 proposes to apply the YRNS tariff differently such that:

- It is only “Low Carbon” plant which remains treated as if its incremental cost follows the purple dotted “Low Carbon” line in figure 2. Therefore the non-shared year round tariff would be subject to its TEC

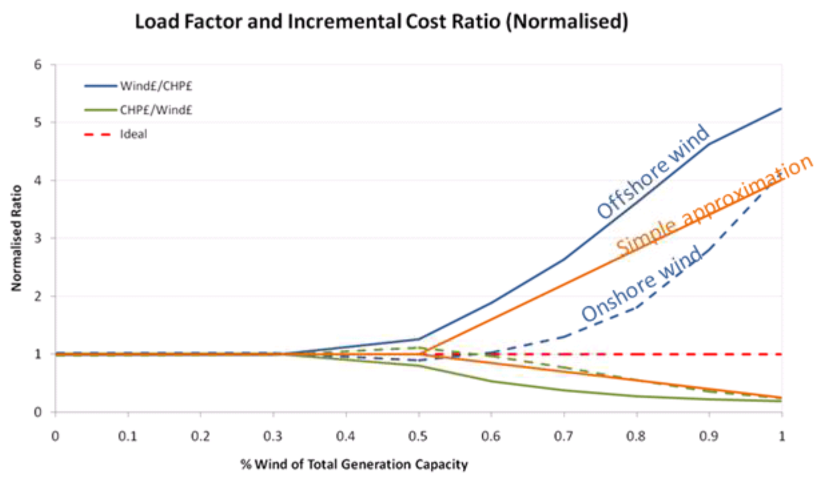
- By contrast, Conventional Carbon plant would instead be treated as if the incremental cost of constraints which it causes, remains on the red dotted “non-low carbon plant” line as described by figure 2. Therefore the non-shared year round tariff would be subject to the ALF for this class of plant. Some workgroup members viewed that this would be more consistent with what the evidence provided by the National Grid Representative from the CMP213 Workgroup indicates.

Effects Tested in Market Model

2.14 The National Grid Representative from CMP213 Workgroup explained further analysis carried out by National Grid during CMP213 using the National Grid ELSI model to create a simplified two node system. This enabled the plant mix in a particular zone to be varied in controlled conditions. This modelling was used to quantify the effect described above to identify how the incremental cost caused by different types of plant changed under varying concentrations of Low Carbon generation.

2.15 Figure 3 which is discussed in more detail in the annex explains the rationale why the Year Round Not Shared tariff is applied when the proportion of Low Carbon compared to total Generation within a zone reaches 50% and above.

Figure 3: Graph from the CMP213 presentation illustrating load factor and Incremental Cost Ratio



2.16 The CMP268 workgroup noted that the orange “simple approximation” line reflects the solution implemented by the CMP213 solution known as Diversity 1 which became CMP213 WACM2, which was ultimately approved by the Authority. The CMP213 solution established a “boundary sharing factor” (BSF) which represented the ratio between carbon and low carbon plant within a zone. This established that in zones with more than 50% low carbon capacity would be subject to a “not-shared year round tariff” charged according to the TEC of a power station.

2.17 It was noted that CMP213 recognised that certain classes of generator gave rise to different constraint costs reflecting the underlying lost opportunity costs for those generators. As a consequence of those costs, transmission investment of a generation zone could be higher than would be envisaged under a linear relationship between constraint costs and transmission investment. Also Transmission Investment is bulky so a perfect 50% relationship may be more theoretical than actual.

2.18 However, some CMP268 workgroup members believed that CMP213 WACM 1 sought to differentiate constraint costs and transmission investment costs by introducing the concept of shared and not shared MWkm. These are established through the boundary sharing factors which reflect the relative diversity of plant within a zone.

Additional discussion of the new CMP213 evidence regarding incremental costs

2.19 In a subsequent meeting The CMP268 Workgroup carried out further consideration and discussion of the previous CMP213 evidence to obtain a better understanding of steps involved in the National Grid CMP213 ELSI analysis. This discussion related to the analysis described above which was used to quantify the relationship between the concentration of Low Carbon generation and the incremental constraint caused by different types of plant. This discussion was facilitated by a presentation provided by the CMP268 proposer included annotated versions of the graphs which had been provided by the National Grid Representative from CMP213 Workgroup. This presentation is described in more detail in Annex 2.

New modelling analysis provided by the National Grid Economics Team

2.20 Analysis was carried out by the National Grid Economics Team for the CMP268 Workgroup using the latest BID3 market modelling tool. The analysis tested whether the new modelling tool would deliver results which are consistent with the older ELSI modelling carried out for CMP213. The result of this analysis was provided to Workgroup and National Grid concluded that it did provide a result which is consistent with the previous National Grid ELSI modelling carried out for CMP213.

2.21 The Proposer argued with agreement from a workgroup member that this new analysis is particularly relevant because it shows that in scenarios where there is a high concentration of Low Carbon generation, the incremental constraint cost caused by wind is much greater than the incremental constraint cost caused by a CCGT by a factor of 4 to 7 times. This is illustrated in Table 1.

Table 1: NG analysis of difference in constraints costs compared to base scenario

Scenario	Difference in constraints compared to base scenario			
	2018		2019	
	Wind	CCGT	Wind	CCGT
Gone Green	16.3%	3.7%	10.3%	1.5%
No Progression	19.7%	4.2%	23.4%	3.3%
Average	18.0%	4.0%	16.9%	2.4%
= Wind - CCGT	14%		14%	

Scenario	Ratio of constraint cost Wind : CCGT	
	2018	2019
	Wind : CCGT	Wind : CCGT
Gone Green	4.4x	6.9x
No Progression	4.7x	7.1x
Average	4.5x	7.0x

Proposer's presentation on NERA/ICL evidence provided as part of CMP213

2.22 The Proposer also presented for the Workgroup for further consideration the previous analysis from NERA/ICL which had been carried out for RWE during the CMP213 process which uses the proprietary Imperial College London Dynamic Transmission Investment Model (DTIM) and suggested how it could be used for CMP268.

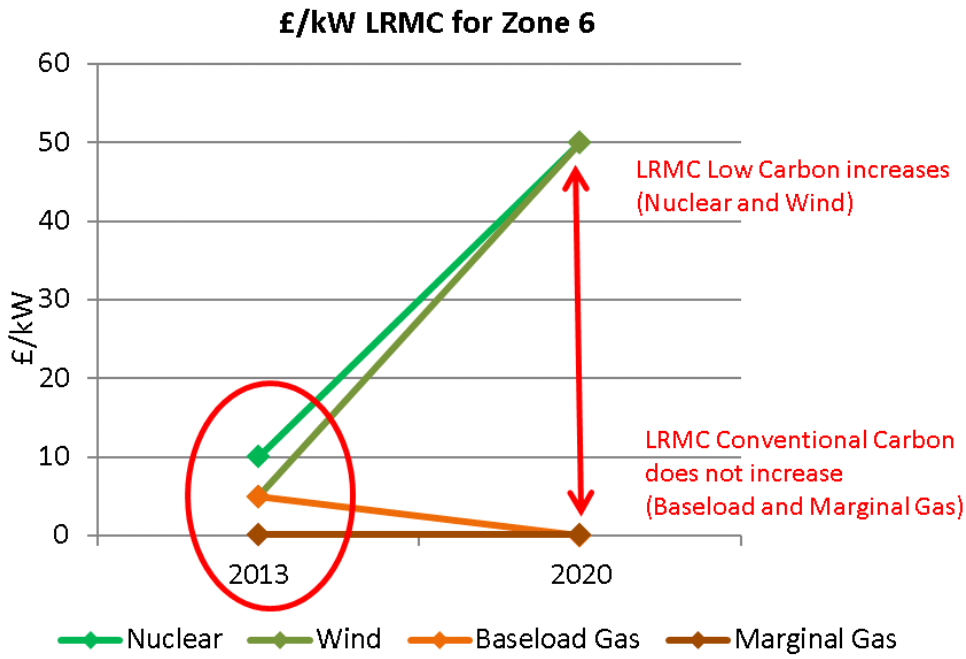
2.23 The Proposer viewed that the NERA/ICL DTIM analysis provided results consistent with the older National Grid ELSI and newer National Grid BID3 analysis that in circumstances where the concentration of Low Carbon generation increases (2020 compared with 2013), then there is a divergence in cost whereby the incremental cost caused by plant classed as Low Carbon (wind and nuclear) increases substantially, while the incremental cost caused by plant classed as Carbon (CCGT) does not increase.

2.24 It was claimed by a member of the workgroup that this comment was made when discussing Sharing, and for all Low Carbon plant regardless of whether or not it was located within a Low Diversity zone. To use this evidence as a basis for charging Conventional Carbon differently in Year Round Not Shared uses the comment out of context.

2.25 A summary extract of reflecting part of the results from the NERA/ICL DTIM analysis is illustrated by the figure 4 below. The proposer explained that that this shows the resulting modelled £/kW LRMC for different types of plant (for example in zone 6) for the two different years of 2013 (during which diversity for zone 6 was relatively high) and 2020 (during which diversity for zone 6 is expected to be relatively low). This shows the cost caused by all plant as being relatively similar in 2013, but then becomes very different for modelled year 2020. This shows that for 2020, LRMC of Low Carbon plant (Nuclear and wind as shown by the green lines) increases substantially compared with their cost in 2013. By contrast, for 2020, the LRMC of plant classed as Conventional Carbon (baseload and marginal gas as shown by the orange lines) does not increase compared with their cost in 2013.

2.26 It was the Proposer's view that this evidence is consistent with and supports the CMP268 proposal.

Figure 4



2.27 The proposer noted that this result was described in the original NERA/ICL report (section 5.2.1. Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA/Imperial College, February 2014) as follows (full text of quote from this section is included in Annex 3 section 2):

"*The high LRMCs for wind in the Scottish zones reflect the fact that, on the margin, additional wind generators in Scotland trigger the need for more reinforcement of the key north-south transmission lines, in particular the HVDC bootstraps…",*

"Our estimated LRMCs for nuclear generators in the Scottish zones also increase materially in the 2020 and 2030 cases, as they also rise to reflect the cost of reinforcing the Scotland-England/Wales boundaries using the HVDC bootstraps…"

*"**In contrast to wind and nuclear, our LRMC estimates for Scottish peaking ("marginal gas") plants do not rise** to a level that reflects the capacity cost of the bootstraps. This reflects the fact that peakers tend to generate in low wind conditions, when the capacity built to transport output from Scottish wind farms to southern load centres (i.e. on the HVDC bootstraps) is not constrained, and thus **these plants are not adding to transmission capacity costs on these boundaries**. In fact, as the north-south transmission lines are reinforced to accommodate growth in generation capacity (especially wind) in Scotland, the LRMCs of Scottish peakers fall as there is more spare transmission capacity in high demand, low wind periods when those peakers are most likely to generate." [emphasis added]*

"We find a similar result for gas plants operating at higher load factors ("baseload gas"). These plants add very little to transmission reinforcement

costs if they are located in England or Wales, but also ***impose a much lower LRMC of transmission than wind farms or nuclear plants in Scotland****. This is because, at times when north-south transmission lines are likely to be constrained (high wind conditions), our modelling suggests these plants are likely to be out of merit. In some cases, it is possible that the model is choosing to constrain down thermal plants in Scotland before curtailing wind output when north-south transmission lines are becoming constrained...*"[emphasis added]

Issue of constrained running

2.28 Another workgroup member argued, and referred to the Empirical evidence of a year's worth of half hourly data presented to the Workgroup by him before send back, that when there is a lot of wind generating at an instant in time in Scotland, it is not necessarily the case (as CMP268 assumes) that the carbon type plant including pumped storage will stop; it may well have to be constrained on (both there and across GB) for reasons of inertia, or more locally for reactive support. The previously-supplied data to the workgroup prior to send-back showed this to be so across a 12 month span.

2.29 The proposer explained that while there may be occurrences of periods where there may be some constrained on generation, this result is entirely consistent with CMP268 for the following reasons:

- Periods of concurrent running caused by constrained on generation from Conventional Carbon generators is not an incremental cost caused by Conventional Carbon generators (SRMC, or LRMC). This is because in circumstances when constrained on generation may be required, there would need to be enough network capacity to accommodate enough constrained on generation from Conventional Carbon generators. It follows that an incremental increase, or reduction in capacity of Conventional Carbon generation would not change this requirement, so it is not an incremental cost. Economic principles of efficient charging arrangements state that cost reflective price signals should only reflect incremental costs. This is further outlined in the CUSC in a section below which was shared with the workgroup:

  > "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." (CUSC Section 14, paragraph 14.14.6) [emphasis added]

- Empirical evidence presented to the Workgroup by the Proposer did demonstrate that in practice Conventional Carbon generation does exhibit a counter correlation with periods when constraints are likely to occur, which is consistent with CMP268. Periods of concurrent running are already reflected by the application of the ALF to the Conventional Carbon tariff

- Conclusions which the other Workgroup member drew from their evidence submitted to the Workgroup which suggested that there was no counter correlation was invalid as explained in detail in the CMP268 FMR and SSE's CMP268 Code Administrator consultation response. In summary that analysis only considered the correlation between Conventional Carbon generation and wind generation, while it failed to take account of correlations with periods when constraints were more likely to occur i.e. conditions where there is a simultaneous relatively high wind and relatively low demand. Also, with respect to the empirical evidence relating to Peterhead Power Station, the 12 month period only included generation data for Peterhead for a small number of days during which Peterhead was generating for commissioning and testing purposes which cannot be taken as representative of normal commercial operation.

2.3 Conclusions

2.3.1 The workgroup discussed the CMP213 presentation and the National Grid Analysis in the context of CMP268.

2.3.2 Some workgroup members believed that the application of the not-shared year round tariff at 100% of TEC to conventional carbon generation could not be justified as cost reflective on the basis of the evidence presented under CMP213. As a result this class of generation should not pay this element of the tariff based on their TEC. Other workgroup members did not agree with this belief.

2.3.3 The Proposer explained the rationale for this conclusion is based on the view that the CMP213 analysis shows that when the concentration of Low Carbon generation exceeds 50%, then the incremental cost caused by Low Carbon generation increases to be greater than that reflected by their ALF, while by contrast, the incremental cost caused by Conventional Carbon generation does not increase to be greater than that reflected by their ALF.

Some workgroup members were of the view that the different parts of the evidence supported this conclusion for the following reasons:

- **Recap of the analysis from the National Grid Representative from CMP213 Workgroup regarding CMP213 -** This presentation demonstrated that the analysis carried out for the CMP213 Workgroup does support the conclusion that CMP268 is more cost reflective than baseline. This analysis shows economic principles and the modelling results that support the position that when the concentration of Low Carbon plant exceeds roughly 50%, then there is a divergence whereby the incremental cost caused by plant classed as Low Carbon increases to be greater than that reflected by their ALF, while the incremental cost caused by plant classed as Carbon does not increase to be greater than their ALF.

- **Additional discussion of the CMP213 analysis regarding incremental costs –** The additional discussion enabled the Workgroup to secure a robust understanding of the methodology used during the CMP213 analysis and therefore have confidence in the way the workgroup interpreted the results.

- **New modelling analysis provided by the National Grid Economics Team –** This new analysis carried out by National Grid using the latest BID3 modelling tools was a useful confirmation of the results previously derived from the older National Grid ELSI modelling tool used during the CMP213 process. These results from the new modelling provide additional confirmation and corroboration that the CMP268 has appropriately identified a defect in the Baseline and that the solution proposed by CMP268 is better than Baseline because it is more cost reflective.

- **Additional discussion of NERA/ICL evidence provided as part of CMP213 -** This NERA/ICL analysis does over state the LRMC for all northern plant due to assuming high cost HVDC is always the marginal reinforcement, however this analysis does provided useful evidence for the value of relative costs. The results from this analysis are consistent with the results described above from both the older National Grid ELSI model (used during the CMP213 process) as well as consistent the new National Grid BID3 model (results of which have been presented during the CMP268 process). This further models a divergence in cost when the concentration of Low Carbon generation increases, such that the incremental cost caused by plant classed as Low Carbon increases, while the incremental cost caused by plant classed as Carbon does not increase. The results from this NERA/ICL modelling provide additional confirmation and corroboration that the CMP268 has appropriately identified a defect in the Baseline and that the solution proposed by CMP268 is better than Baseline because it is more cost reflective.

2.3.4 However, other workgroup members were of the view that the issue identified under CMP268 related to the methodology used to derive the tariff Consequently CMP268 does not address the rationale for the Sharing Methodology established under CMP213.

2.3.5 Some members of the workgroup suggested that CMP268 was more cost reflective in relation to incremental cost drivers.

3 Impacts

3.1 Introduction

3.1.1 The Workgroup noted that the Authority asked the Workgroup to undertake the following:

"*The FMR [Final Modification Report] should consider in more depth the potential impacts of the proposed solution, as compared to retaining the current system*" (Ofgem Send Back Letter, 2 December 2016).

3.1.2 In order the fulfil this request the workgroup considered the potential impact of CMP268 on the following: :

- Absolute TNUoS charges;
- Locational signals and tariffs;
- The effect on the "year round adjustment factor"
- The effects of a reduction in capacity of Conventional Carbon generation in Scotland on tariffs;
- The effects on generation charging zones with a negative YRNS tariff; and
- CMP268 tariffs compared with SQSS scaling factors and actual transmission investment

3.2 CMP268 and absolute TNUoS Charges

3.2.1 For conventional carbon generation CMP268 will replace TEC with the ALF as the charging base for the year round not shared tariff. Since this tends to reduce the amount of costs recovered from this element of the tariff (since the ALF is lower than the TEC) it will result in an adjustment to the generation residual to account for this change and ensure cost recovery.

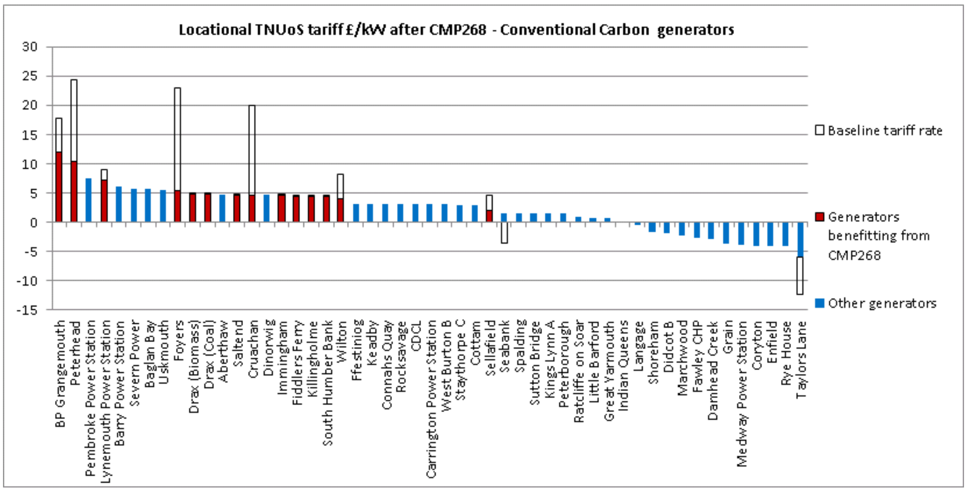
3.2.2 Analysis undertaken by National Grid suggested that the resultant adjustment to the Generation tariff was an increase of 0.23£/kw in the [generation] residual tariff [2018/19]. It was noted that this is within the normally expected range of variation of TNUoS tariffs which tends to occur due to changes in input data between published forecasts.

3.2.3 Some workgroup members concluded from this analysis that for those generators which are directly affected, CMP268 will result in relatively large changes in their TNUoS tariffs. The Proposer presented the argument that this illustrates the relatively large value of the defect and the relatively large value of the distortion to effective competition and discrimination caused by the defect in the Baseline methodology.

3.3 CMP268 and locational tariffs £/kW

3.3.1 CMP268 will change the liability for the not shared component of the year round generation tariff for conventional carbon by applying the ALF. The £/kW value of the locational elements of the TNUoS tariff (Peak Security plus Year Round Shared plus Year Round Not Shared) both for the Baseline and after CMP268 proposal for 2018/19 are illustrated in Figure 4 (excluding the Generation Residual). This graph was presented by the proposer to the workgroup and is based on National Grid forecast of TNUoS tariffs for 2018/19 and published in February 2017.

Figure 5: Impact on locational TNUoS tariffs for conventional carbon generators under CMP268.



3.3.2 For certain generators there is a marked reduction in liability for TNUoS tariffs in those zones subject to the not shared year round tariff as a consequence of CMP268.

3.3.3 The Proposer stated that figure 5 shows that individual Conventional Carbon generators affected by CMP268 are currently paying amongst the most expensive TNUoS charges of all Conventional Carbon generators and after CMP268, they will continue to be paying amongst the most expensive TNUoS charges of all Conventional Carbon generators. This is illustrated by sorting generators from left to right with those generators facing the most expensive post CMP268 charges on the left hand side. The red bars represent those generators which experience a reduced charge following CMP268 and are shown clustered on the left hand side of the graph because their post CMP268 locational charges are still among the most expensive of all Conventional Carbon generators in GB.

3.3.4 The Proposer also stated that the graph also illustrates that for the two generators which experience an increase in locational charge post CMP268 (Seabank and Taylors Lane), even if CMP268 was implemented they will still be paying amongst the lowest locational charges of all Conventional Carbon generators in GB.

3.4 Impact on effective Year Round adjustment factor

3.4.1 The Proposer presented additional analysis to the workgroup which derived an “effective adjustment factor” which could be applied to the total Year Round tariff (including both “shared” and “not shared” elements) for different generators[1] (Figure 5). Some workgroup member were of the view that this data illustrates the “effective” ALF adjustment required to a generator’s entire year round tariff (combination of “shared” plus “not shared” elements) in order to derive the same year round charge paid by the generator under Baseline compared with CMP268 and published ALF. For the Baseline, this means the “effective” ALF is an adjustment equivalent to applying ALF to the shared element of the tariff and TEC to the not shared element of the tariff.

3.4.2 In the graph:

- **Black diamond outlines** -Show the published ALF for Conventional Carbon each station
- **Green shaded diamonds -** Show stations where their Baseline Year Round adjustment factor matches their ALF (i.e. where their YRNS tariff is zero)
- **Red shaded diamonds** – Show stations where their Baseline Year Round adjustment factor does not match their ALF (i.e. where their YRNS tariff is not zero)

Figure 6: The effect of the year round adjustment factor

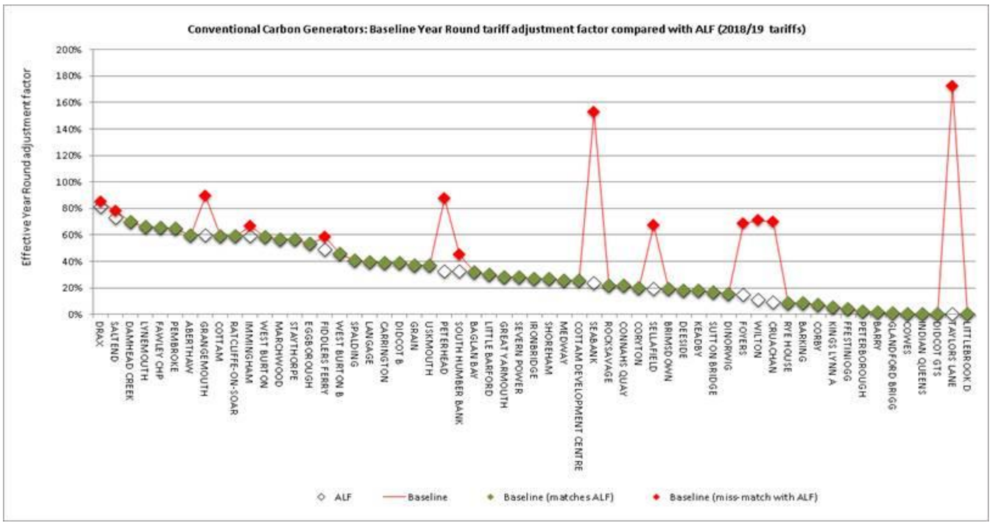
[1] This analysis takes the following approach:

1) Calculation 1: “Total Year Round tariff” for a particular zone can be described as the unadjusted sum of both Year Round £/kW tariff elements for the relevant zone i.e. (YRS+YRNS).

2) Calculation 2: “Year Round charge paid” by individual Conventional Carbon generators is currently calculated by the Baseline as (YRSxALF)+(YRNSx100%). By contrast, the “Year Round charge paid” within CMP268 is different and would be calculated as (YRSXALF)+(YRNSXALF).

3) Calculation 1 divided by Calculation 2: “Effective Year Round adjustment factor” is calculated as calculation 1: “Year Round charge paid” divided by calculation 2: “Total Year Round tariff” as defined above for the relevant zone. Most Conventional Carbon generators are in a zone where the value of the YRNS tariff element is zero, therefore within Baseline, they already have their ALF applied to their whole “total Year Round tariff”, and so their “effective Year Round adjustment factor” is already equal to their ALF. However for a minority of Conventional Carbon generators who find themselves in a zone with a non-zero YRNS tariff, their “Effective Year Round adjustment factor” will be different from their ALF.

The data is from the latest National Grid published ALFs and the National Grid published 5 Year TNUoS forecast from 28th February 2017



3.4.3 The proposer was of the view that the following conclusions could be drawn from this analysis:

- For Conventional Carbon generators, the range of ALFs can be described as a continuous distribution. It follows that the differences in ALF do not provide any justification for the charging methodology to treat Conventional Carbon generators of different technology types any differently from each other for example CCGTs as compared with OCGTs, or other peaking plant.

- CMP268 can be best characterised in terms of treating all Conventional Carbon generators the same as each other. By comparison, it is the Baseline which currently treats a minority of Conventional Carbon generators differently from the other generators of the same type. This is because within Baseline, for the majority of Conventional Carbon generators (46 out of 59 of them), their effective Year Round tariff adjustment factor is already equal to their ALF. By contrast, it is only a minority of Conventional Carbon generators which the Baseline currently treats differently (only 13 stations).

3.4.4 One workgroup member wasn't convinced that this illustrated anything other than the effect of not allowing ALF to be applied to non-shared year round tariffs. By definition a calculation comparing charges where it can be applied will show differences. The working group member was also concerned that the proposer was using ratios for the analysis. To show differences more accurately, the workgroup felt that nominal values should be used, as ratios can be misleading, particularly for small or negative numbers.

3.4.5 The Proposer noted that for some Conventional Carbon generators in <u>positive</u> YRNS tariff zones, the Baseline is resulting in an effective Year Round tariff adjustment factor which is well in excess of that indicated by their ALF. For example, Peterhead Baseline tariff for 2018/19 is £22.05 per kW [(£4.76X32%) + (20.51X100%)]. He stated that this results in an effective Year Round tariff adjustment factor of 87% i.e. <u>Peterhead's Year Round charge paid is 87% of its total</u>

Year Round tariff [calculated as £22.05 / (£4.76+£20.51)]. This 87% is greatly in excess of Peterhead's ALF of 32%. For the avoidance of doubt, CMP268 would reduce the effective Year Round tariff adjustment factor to the station's ALF of 32%.

3.4.6 In addition the Proposer explained that for some generators in negative YRNS tariff zones, the Baseline results in an effective Year Round tariff adjustment factor which may be in excess of 100% of the total Year Round tariff for their zone and stated that this is a strange outcome. This means that Year Round tariff element they face within Baseline may be much more extreme than would be suggested by simply applying the total Year Round tariff to 100% of their TEC. The Proposer observed this result occurs situations where the YRS tariff element (to which ALF is applied) is a positive charge, while the YRNS tariff (which is applied at 100% of TEC) is a negative charge. An example of this is Taylors Lane which has a Baseline tariff of -£6.49 per kW [(£2.73X0%) + (-£6.49X100%)] which is **172%** of their full year Round tariff of -£3.77 per kW (£2.73+-£6.49). For the avoidance of doubt, CMP268 would reduce the effective full Year Round adjustment factor for Taylors Lane to the station's ALF of 0%. Taylors Layne has an ALF of zero due to its characteristic of being a relatively low efficiency peaking plant which has very rarely generated in the recent past.

3.4.7 A member of the group believed that the present treatment of negative zones under CMP213 was appropriate as it simply reflected a mathematical outcome of what happened when the YR shared part of the signal consisted of a positive number, but the overall charge was a negative number. Whenever there is a positive shared YR charge then the resulting effective charge after the ALF is applied will be lower than before the ALF. If the total charge was negative due to one or more of the other charges (either in the peak charge, YR not shared charge or indeed residual charge) being negative, then the resulting effective charge after the ALF is applied will always be more negative than before it is applied. The workgroup member noted that this effect could still occur under CMP268 if the peak or residual charge caused the overall charge to be negative, instead of the YR unshared doing so

3.4.8 The workgroup noted that CMP268 impacts in negative charging zones where there is a not shared element of the year round tariff.

3.5 Impact on tariffs of a sensitivity reduction in capacity of Conventional Carbon generation in Scotland.

3.5.1 As part of the send back Ofgem asked for some distributional impact analysis. National Grid therefore showed the impact on tariffs if a Conventional Carbon generator in an area of Low Diversity was to reduce or increase its Capacity. For the purposes of the analysis Foyers was chosen as an example but please note Foyers was chosen for purely illustrative purposes and the increase/reduction does not reflect their actual contracted future position.

The results of this analysis can be found in Table 1 and Table 2 below. Table 1shows the change in tariffs under the existing methodology and Table 2 shows the change in tariffs under the new proposed methodology. The examples have been changed in Table 2 to highlight that Conventional Carbon and Non-Conventional Carbon generation would be affected differently under the proposed methodology. In reality however there are currently no Non-Conventional Carbon Generators.

3.5.2 Looking at the numbers under the current methodology if Carbon Generation is increased then tariffs go down for both Conventional and Intermittent generation as circuits move from being Year Round Not Shared to Year Round Shared (with the Year Round Not Shared charged based TEC and not adjusted by Load Factor) and vice versa for decreases. Circuits move from being YRNS to YRS due to the increase in Diversity. The opposite happens when decreasing TEC

3.5.3 A Workgroup member stated that the change in tariffs would be what you would expect to happen under the current Charging Methodology and you should expect tariffs to change due to the actions of others.

3.5.4 The National Grid representative agreed that you should expect change but logically would you not expect the opposite to happen?

3.5.5 Under the new methodology the changes still occur in the same direction and magnitude for Intermittent generation but Conventional Carbon is largely unaffected by changes in TEC as the charging arrangement for YRNS and YRS are the same for Conventional Carbon so they are unaffected by the change in Diversity.

Table 2

Differences under existing Methodology

INCREASE FOYERS 300

Zone No.	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Residual (£/kW)	80% Conventional	40% Intermittent
1	0.19	2.48	-2.47	0.03	-0.27	-1.45
2	0.08	2.47	-2.47	0.03	-0.38	-1.45
3	0.14	2.34	-2.28	0.03	-0.24	-1.32
4	0.14	2.34	-2.28	0.03	-0.24	-1.32
5	0.09	1.89	-1.86	0.03	-0.24	-1.08
6	0.14	1.91	-1.85	0.03	-0.16	-1.06
7	0.24	1.44	-1.43	0.03	-0.02	-0.83
8	0.14	1.44	-1.38	0.03	-0.07	-0.78
9	0.09	0.83	-0.81	0.03	-0.03	-0.46
10	0.08	1.03	-1.05	0.03	-0.12	-0.61
11	0.08	1.03	-1.02	0.03	-0.08	-0.58
12	0.07	0.54	-0.51	0.03	0.02	-0.27
13	0.05	0.25	-0.23	0.03	0.05	-0.10
14	0.05	0.25	-0.20	0.03	0.08	-0.08
15	0.04	0.06	-0.02	0.03	0.09	0.03
16	0.04	0.05	0.00	0.03	0.10	0.05
17	0.02	0.03	0.00	0.03	0.07	0.04
18	0.03	0.03	0.00	0.03	0.08	0.04
19	0.04	0.07	0.00	0.03	0.12	0.05
20	0.05	0.06	0.00	0.03	0.12	0.05
21	0.05	0.05	0.00	0.03	0.12	0.05
22	0.04	-0.12	0.17	0.03	0.14	0.15
23	0.03	-0.12	0.15	0.03	0.11	0.13
24	-0.08	-0.12	0.00	0.03	-0.15	-0.02
25	-0.01	-0.09	0.00	0.03	-0.05	-0.01
26	-0.37	-0.33	0.00	0.03	-0.60	-0.10
27	-0.24	-0.23	0.00	0.03	-0.40	-0.07

Differences

DECREASE FOYERS 300

Zone No.	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Residual (£/kW)	80% Conventional	40% Intermittent
1	0.19	-2.78	2.80	-0.04	0.72	1.64
2	0.08	-2.79	2.80	-0.04	0.60	1.64
3	0.14	-2.52	2.58	-0.04	0.66	1.53
4	0.14	-2.52	2.58	-0.04	0.66	1.53
5	0.09	-1.99	2.02	-0.04	0.47	1.18
6	0.14	-1.99	2.05	-0.04	0.55	1.20
7	0.24	-1.43	1.43	-0.04	0.48	0.82
8	0.14	-1.43	1.48	-0.04	0.44	0.87
9	0.09	-0.77	0.78	-0.04	0.22	0.43
10	0.08	-1.04	1.03	-0.04	0.23	0.57
11	0.08	-1.04	1.06	-0.04	0.26	0.60
12	0.07	-0.49	0.52	-0.04	0.15	0.28
13	0.05	-0.19	0.21	-0.04	0.06	0.09
14	0.05	-0.19	0.23	-0.04	0.09	0.11
15	0.04	0.02	0.02	-0.04	0.03	-0.02
16	0.04	0.05	0.00	-0.04	0.03	-0.02
17	0.02	0.03	0.00	-0.04	0.00	-0.03
18	0.03	0.03	0.00	-0.04	0.01	-0.03
19	0.04	0.07	0.00	-0.04	0.05	-0.02
20	0.05	0.06	0.00	-0.04	0.05	-0.02
21	0.05	0.05	0.00	-0.04	0.04	-0.02
22	0.04	-0.12	0.17	-0.04	0.07	0.08
23	0.03	-0.12	0.15	-0.04	0.04	0.06
24	-0.08	-0.12	0.00	-0.04	-0.22	-0.09
25	-0.01	-0.09	0.00	-0.04	-0.12	-0.08
26	-0.37	-0.33	0.00	-0.04	-0.68	-0.18
27	-0.24	-0.23	0.00	-0.04	-0.47	-0.14

Table 3

Differences under proposed CMP268 methodology

INCREASE FOYERS 300

					Example		
					80%	80%	40%
Zone No.	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Residual (£/kW)	Conventional Carbon	Non Conventional Carbon	Intermittent
1	0.19	2.48	-2.47	0.07	0.27	-0.23	-1.41
2	0.08	2.47	-2.47	0.07	0.15	-0.34	-1.41
3	0.14	2.34	-2.28	0.07	0.26	-0.20	-1.28
4	0.14	2.34	-2.28	0.07	0.25	-0.20	-1.28
5	0.09	1.89	-1.86	0.07	0.17	-0.20	-1.04
6	0.14	1.91	-1.85	0.07	0.25	-0.12	-1.02
7	0.24	1.44	-1.43	0.07	0.31	0.02	-0.79
8	0.14	1.44	-1.38	0.07	0.25	-0.03	-0.74
9	0.09	0.83	-0.81	0.07	0.17	0.01	-0.42
10	0.08	1.03	-1.05	0.07	0.13	-0.07	-0.57
11	0.08	1.03	-1.02	0.07	0.16	-0.04	-0.54
12	0.07	0.54	-0.51	0.07	0.16	0.06	-0.23
13	0.05	0.25	-0.23	0.07	0.13	0.09	-0.06
14	0.05	0.25	-0.20	0.07	0.16	0.12	-0.04
15	0.04	0.06	-0.02	0.07	0.14	0.13	0.07
16	0.04	0.05	0.00	0.07	0.14	0.14	0.09
17	0.02	0.03	0.00	0.07	0.11	0.11	0.08
18	0.03	0.03	0.00	0.07	0.12	0.12	0.08
19	0.04	0.07	0.00	0.07	0.16	0.16	0.09
20	0.05	0.06	0.00	0.07	0.16	0.16	0.09
21	0.05	0.05	0.00	0.07	0.16	0.16	0.09
22	0.04	-0.12	0.17	0.07	0.15	0.18	0.19
23	0.03	-0.12	0.15	0.07	0.12	0.15	0.17
24	-0.08	-0.12	0.00	0.07	-0.11	-0.11	0.02
25	-0.01	-0.09	0.00	0.07	-0.01	-0.01	0.03
26	-0.37	-0.33	0.00	0.07	-0.56	-0.56	-0.06
27	-0.24	-0.23	0.00	0.07	-0.36	-0.36	-0.03

DECREASE FOYERS 300

					Example		
					80%	80%	40%
Zone No.	Peak Security (£/kW)	Year Round Shared (£/kW)	Year Round Not Shared (£/kW)	Residual (£/kW)	Conventional Carbon	Non Conventional Carbon	Intermittent
1	0.19	-2.78	2.80	-0.10	0.10	0.66	1.59
2	0.08	-2.79	2.80	-0.10	-0.01	0.55	1.58
3	0.14	-2.52	2.58	-0.10	0.09	0.61	1.47
4	0.14	-2.52	2.58	-0.10	0.09	0.61	1.47
5	0.09	-1.99	2.02	-0.10	0.01	0.42	1.13
6	0.14	-1.99	2.05	-0.10	0.09	0.50	1.15
7	0.24	-1.43	1.43	-0.10	0.14	0.43	0.76
8	0.14	-1.43	1.48	-0.10	0.09	0.38	0.81
9	0.09	-0.77	0.78	-0.10	0.01	0.17	0.38
10	0.08	-1.04	1.03	-0.10	-0.03	0.18	0.52
11	0.08	-1.04	1.06	-0.10	0.00	0.21	0.55
12	0.07	-0.49	0.52	-0.10	0.00	0.10	0.23
13	0.05	-0.19	0.21	-0.10	-0.03	0.01	0.04
14	0.05	-0.19	0.23	-0.10	-0.01	0.04	0.06
15	0.04	0.02	0.02	-0.10	-0.03	-0.02	-0.07
16	0.04	0.05	0.00	-0.10	-0.02	-0.02	-0.08
17	0.02	0.03	0.00	-0.10	-0.05	-0.05	-0.09
18	0.03	0.03	0.00	-0.10	-0.04	-0.04	-0.08
19	0.04	0.07	0.00	-0.10	0.00	0.00	-0.07
20	0.05	0.06	0.00	-0.10	0.00	0.00	-0.07
21	0.05	0.05	0.00	-0.10	-0.01	-0.01	-0.08
22	0.04	-0.12	0.17	-0.10	-0.01	0.02	0.03
23	0.03	-0.12	0.15	-0.10	-0.04	-0.01	0.01
24	-0.08	-0.12	0.00	-0.10	-0.27	-0.27	-0.14
25	-0.01	-0.09	0.00	-0.10	-0.18	-0.18	-0.13
26	-0.37	-0.33	0.00	-0.10	-0.73	-0.73	-0.23
27	-0.24	-0.23	0.00	-0.10	-0.52	-0.52	-0.19

3.5.6 The Proposer presented to the Workgroup table 4 below which shown below based on Baseline tariffs which had been provided to the Workgroup by National Grid.

3.5.7 The Proposer explained that this table shows that for generators with the same load factor (this example assumed 40%), the Baseline methodology results in exactly the same Year Round charge for both Conventional Carbon generators and Low Carbon intermittent generators for all zones, as shown by the ratio of “1” in the table below. Some workgroup members concluded that this result is not consistent with the evidence described above that the cost caused by these different types of generator are different from each other and that this difference should be reflected by the tariffs which they pay.

		Baseline YR Charge					
		With Foyers			Without Foyers		
Zone No.	Zone Name	Conventional	Intermittent	Ratio	Conventional	Intermittent	Ratio
1	North Scotland	25.35	25.35	1.00	26.42	26.42	1.00
2	East Aberdeenshire	22.42	22.42	1.00	23.50	23.50	1.00
3	Western Highlands	24.68	24.68	1.00	25.66	25.66	1.00
4	Skye and Lochalsh	30.24	30.24	1.00	31.22	31.22	1.00
5	Eastern Grampian and Tayside	22.73	22.73	1.00	23.42	23.42	1.00
6	Central Grampian	22.74	22.74	1.00	23.56	23.56	1.00
7	Argyll	30.48	30.48	1.00	31.10	31.10	1.00
8	The Trossachs	20.11	20.11	1.00	20.64	20.64	1.00
9	Stirlingshire and Fife	16.32	16.32	1.00	16.36	16.36	1.00
10	South West Scotlands	17.83	17.83	1.00	18.25	18.25	1.00
11	Lothian and Borders	12.29	12.29	1.00	12.90	12.90	1.00
12	Solway and Cheviot	10.04	10.04	1.00	10.27	10.27	1.00
13	North East England	5.42	5.42	1.00	5.56	5.56	1.00
14	North Lancashire and The Lakes	4.08	4.08	1.00	4.17	4.17	1.00
15	South Lancashire, Yorkshire and H	0.41	0.41	1.00	0.52	0.52	1.00
16	North Midlands and North Wales	-0.27	-0.27	1.00	-0.26	-0.26	1.00
17	South Lincolnshire and North Norf	0.05	0.05	1.00	0.05	0.05	1.00
18	Mid Wales and The Midlands	0.13	0.13	1.00	0.13	0.13	1.00
19	Anglesey and Snowdon	-0.55	-0.55	1.00	-0.53	-0.53	1.00
20	Pembrokeshire	-1.55	-1.55	1.00	-1.55	-1.55	1.00
21	South Wales & Gloucester	-1.57	-1.57	1.00	-1.57	-1.57	1.00
22	Cotswold	-5.59	-5.59	1.00	-5.58	-5.58	1.00
23	Central London	-5.40	-5.40	1.00	-5.40	-5.40	1.00
24	Essex and Kent	1.09	1.09	1.00	1.09	1.09	1.00
25	Oxfordshire, Surrey and Sussex	-0.94	-0.94	1.00	-0.94	-0.94	1.00
26	Somerset and Wessex	-1.39	-1.39	1.00	-1.39	-1.39	1.00
27	West Devon and Cornwall	-1.99	-1.99	1.00	-1.99	-1.99	1.00

Table 4: Source: TNUoS tariffs provided to the Workgroup by National Grid for 2018/19 to illustrate the sensitivity of Foyers closing.

3.5.8 The proposer also provided to the Workgroup table 5 shown below also based on tariffs arising from CMP268 which had been provided to the Workgroup by National Grid. The Proposer presented that two key conclusions could be drawn from this analysis as illustrated by the annotated arrows:

3.5.9 Firstly, the Proposer explained that this shows that for zones with a positive YRNS tariff, then CMP268 would result in a divergence in charges between Conventional Carbon generators and Intermittent (Low Carbon). Some Workgroup members suggested this result is more consistent with the evidence described above. By contrast, for high diversity zones, the TNUoS charges following from CMP268 would provide the same charge for these two different types of generator, in the same way as the Baseline. This is also consistent with the evidence descried above.

3.5.10 Secondly, the Proposer suggested that this shows that in the sensitivity testing the impact on TNUoS charges if Foyers were to close, then CMP268 would result in a widening divergence between the charges paid by Conventional Carbon generators and Low Carbon generators (Year Round charge for Conventional Carbon generators reduces, while the Year Round charge for Low Carbon intermittent generators increases). The Proposer stated that this result is also more consistent with the evidence described above. The proposer noted that Baseline does not show any such increasing divergence since the TNUoS charges for the two types of generator remain the same as each other irrespective of how the level of diversity may change.

		CMP268 YR Charge					
		With Foyers			Without Foyers		
Zone No.	Zone Name	Conventional	Intermittent	Ratio	Conventional	Intermittent	Ratio
1	North Scotland	13.04	25.35	1.9	12.77	26.42	2.07
2	East Aberdeenshire	10.11	22.42	2.2	9.84	23.50	2.39
3	Western Highlands	12.60	24.68	2.0	12.35	25.66	2.08
4	Skye and Lochalsh	14.82	30.24	2.0	14.58	31.22	2.14
5	Eastern Grampian and Tayside	11.46	22.73	2.0	11.23	23.42	2.09
6	Central Grampian	11.46	22.74	2.0	11.29	23.56	2.09
7	Argyll	14.20	30.48	2.1	14.09	31.10	2.21
8	The Trossachs	10.04	20.11	2.0	9.90	20.64	2.08
9	Stirlingshire and Fife	7.73	16.32	2.1	7.54	16.36	2.17
10	South West Scotlands	8.68	17.83	2.1	8.62	18.25	2.12
11	Lothian and Borders	6.47	12.29	1.9	6.48	12.90	1.99
12	Solway and Cheviot	4.92	10.04	2.0	4.91	10.27	2.09
13	North East England	2.69	5.42	2.0	2.73	5.56	2.03
14	North Lancashire and The Lakes	2.16	4.08	1.9	2.18	4.17	1.91
15	South Lancashire, Yorkshire and Humber	0.32	0.41	1.3	0.41	0.52	1.29
16	North Midlands and North Wales	-0.27	-0.27	1.0	-0.26	-0.26	1.00
17	South Lincolnshire and North Norfolk	0.05	0.05	1.0	0.05	0.05	1.00
18	Mid Wales and The Midlands	0.13	0.13	1.0	0.13	0.13	1.00
19	Anglesey and Snowdon	-0.55	-0.55	1.0	-0.53	-0.53	1.00
20	Pembrokeshire	-1.55	-1.55	1.0	-1.55	-1.55	1.00
21	South Wales & Gloucester	-1.57	-1.57	1.0	-1.57	-1.57	1.00
22	Cotswold	-1.58	-5.59	3.5	-1.58	-5.58	3.53
23	Central London	-1.51	-5.40	3.6	-1.51	-5.40	3.58
24	Essex and Kent	1.09	1.09	1.0	1.09	1.09	1.00
25	Oxfordshire, Surrey and Sussex	-0.94	-0.94	1.0	-0.94	-0.94	1.00
26	Somerset and Wessex	-1.39	-1.39	1.0	-1.39	-1.39	1.00
27	West Devon and Cornwall	-1.99	-1.99	1.0	-1.99	-1.99	1.00

Table 5

3.5.11 The Proposer used the same tariff data to present the impact of the removal of Foyers on generation plant with a range of different characteristics shown in table 5. The table shows the calculated change in Year Round charge caused by the removal of Foyers within both the Baseline and CMP268 methodologies.

		Change in YR charge without Foyers								
		Combined YR tariff	Baseline				CMP268			
Zone No.	Zone Name		Conventional 80%	Conventional 40%	Conventional 0%	Intermittent	Conventional 80%	Conventional 40%	Conventional 0%	Intermittent
1	North Scotland	-0.68	-0.09	1.08	2.25	1.08	-0.54	-0.27	0.00	1.08
2	East Aberdeenshire	-0.67	-0.08	1.08	2.25	1.08	-0.53	-0.27	0.00	1.08
3	Western Highlands	-0.61	-0.08	0.98	2.04	0.98	-0.49	-0.24	0.00	0.98
4	Skye and Lochalsh	-0.61	-0.08	0.98	2.04	0.98	-0.49	-0.24	0.00	0.98
5	Eastern Grampian and Tayside	-0.57	-0.15	0.69	1.53	0.69	-0.46	-0.23	0.00	0.69
6	Central Grampian	-0.42	-0.01	0.82	1.64	0.82	-0.34	-0.17	0.00	0.82
7	Argyll	-0.27	0.02	0.62	1.21	0.62	-0.22	-0.11	0.00	0.62
8	The Trossachs	-0.36	-0.06	0.53	1.13	0.53	-0.29	-0.14	0.00	0.53
9	Stirlingshire and Fife	-0.48	-0.31	0.04	0.38	0.04	-0.39	-0.19	0.00	0.04
10	South West Scotlands	-0.16	0.03	0.42	0.80	0.42	-0.13	-0.06	0.00	0.42
11	Lothian and Borders	0.03	0.22	0.61	0.99	0.61	0.02	0.01	0.00	0.61
12	Solway and Cheviot	-0.01	0.07	0.23	0.38	0.23	-0.01	0.00	0.00	0.23
13	North East England	0.11	0.12	0.14	0.16	0.14	0.09	0.04	0.00	0.14
14	North Lancashire and The Lakes	0.06	0.07	0.09	0.11	0.09	0.05	0.02	0.00	0.09
15	South Lancashire, Yorkshire and Humber	0.22	0.18	0.11	0.04	0.11	0.17	0.09	0.00	0.11
16	North Midlands and North Wales	0.02	0.02	0.01	0.00	0.01	0.02	0.01	0.00	0.01
17	South Lincolnshire and North Norfolk	0.01	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00
18	Mid Wales and The Midlands	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	Anglesey and Snowdon	0.04	0.04	0.02	0.00	0.02	0.04	0.02	0.00	0.02
20	Pembrokeshire	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	South Wales & Gloucester	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Cotswold	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.01
23	Central London	-0.01	-0.01	0.00	0.00	0.00	-0.01	0.00	0.00	0.00
24	Essex and Kent	-0.01	-0.01	0.00	0.00	0.00	-0.01	0.00	0.00	0.00
25	Oxfordshire, Surrey and Sussex	-0.01	-0.01	0.00	0.00	0.00	-0.01	0.00	0.00	0.00
26	Somerset and Wessex	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	West Devon and Cornwall	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table 6

3.5.12 Some workgroup members suggested that the analysis showed the following impacts on the Year Round tariff for Baseline using Zone 1 as an example:

- Baseline Year Round charge is shown to reduce for a high load factor baseload Conventional Carbon generator (reduced by £0.09 per kW) to reflect the reduced North to South flows following the removal of Foyers.

- However, Baseline also shows a significant increase in the charge for a mid merit medium load factor Conventional Carbon Generator (increased by £1.08 per kW) and

- Baseline shows the largest increase for the lowest load factor peaking Conventional Carbon generator (increased by £2.25 per kW).

3.5.13 Some workgroup members noted that this analysis shows that CMP268 would mean that the removal of Foyers would have a different impact on the Year Round tariff paid by generators in Zone 1 as compared with Baseline:

- CMP268 is similar to Baseline in as far as the analysis shows a reduction in charges for a high load factor baseload generator (reduced by £0.56 per kW) to reflect the reduced North to South flows following the removal of Foyers.

- For a mid merit, medium load factor generator, CMP268 shows a smaller reduction (reduced by £0.27 per kW) in Year Round charge, which is a smaller reduction compared with the high load factor plant.

- For a low load factor peaking plant, CMP268 shows no change in charge (charge unchanged), which reflects the fact that a 0% load factor peaking plant does not cause any constraint cost related to the Year Round background to begin with,

3.5.14 Some workgroup members were of the view that the results from this impact analysis supports the position that CMP268 is more cost reflective for all of the generators illustrated above for the following reasons:

3.5.15 Firstly because Baseline provides the wrong investment signal such that the more Conventional Carbon which closes, the worse the Baseline investment signal becomes for remaining, or potential new Conventional Carbon in that zone. This Baseline effect tends to push the market away from equilibrium, which is the opposite of how market price signals should behave.

3.5.16 Secondly, CMP268 delivers the more cost reflective result that Carbon generators with the highest impact and therefore highest exposure to the cost of constraints (higher ALF generators) should experience a larger impact on their tariff when there is a change in the Year Round transport of electricity, but the reverse effect is shown by Baseline.

3.5.17 Thirdly, as an extreme case of the second point above, CMP268 is more cost reflective for a 0% ALF generator which should not pay any Year Round charge irrespective of how the Year Round tariff may change. This reflects the fact that a generator which does not generate does not have any impact on the cost of managing constraints, so does not have any impact on the cost of network investment within the SQSS Economy Criteria as reflected by the ICRP Year Round background. It is therefore more cost reflective for CMP268 to result in no change in the Year Round tariff for 0% generators, as compared with Baseline which showed the complete opposite of resulting in the largest change in tariff for 0% ALF Carbon generators.

3.5.18 Fourthly, this means that within Baseline the more Conventional Carbon that closes in a northern zone, the worse the relative competitive position would become particularly for the very lowest load factor Conventional Carbon generators either remaining, or considering building in that zone compared with other zones in GB. The Proposer suggested this is the opposite of the change in investment signal which would be expected from a cost reflective charging methodology as described in the evidence presented in this report.

3.5.19 A workgroup member was concerned that CMP268 would have inappropriate effects on the charges of carbon plant in negative charging zones as low load factor carbon plant would have their charges increased under CMP268. The workgroup member pointed out the wide difference between low carbon and carbon plant in the zones 22 and 23 in the proposer's analysis. The workgroup member noted that the premise of CMP268 is that carbon generators should be exposed to different (lower) charges as they have higher bid prices than wind farms and therefore should be a lower cost option in order to alleviate constraints. However, in negative zones generators would generally be on the other side of the constraint. Therefore, in this instance the offer price would be relevant to the cost of the constraint not the bid price.

3.5.20 The workgroup member couldn't see a rationale why wind plant would be treated preferentially to carbon plant as a result. The workgroup member noted that wind plant are not in a position to provide a significant volumes of offers as they generally generate as high as they can in order to maximise energy and renewable support revenue, not holding back to provide offers – whilst carbon plant are generally available to provide offers. Therefore, the workgroup member argued that a carbon plant's presence on the import side of the constraint is arguably more valuable.

3.5.21 The workgroup member provided a graph to illustrate the sort of disparity which could be introduced. This is shown below in figure xxx. It looks at the £/kW implications of CMP268 if it were introduced to the current charges in the Cotswold zone. The red line is the current charge which would apply to all types of station. If CMP268 were to be introduced, then low carbon (wind) stations would remain on the red line. Carbon stations would move to the blue line. The work group member believed that, for reasonable load factors, this illustrated that under CMP268 wind stations would be treated significantly more favourably than carbon plant.

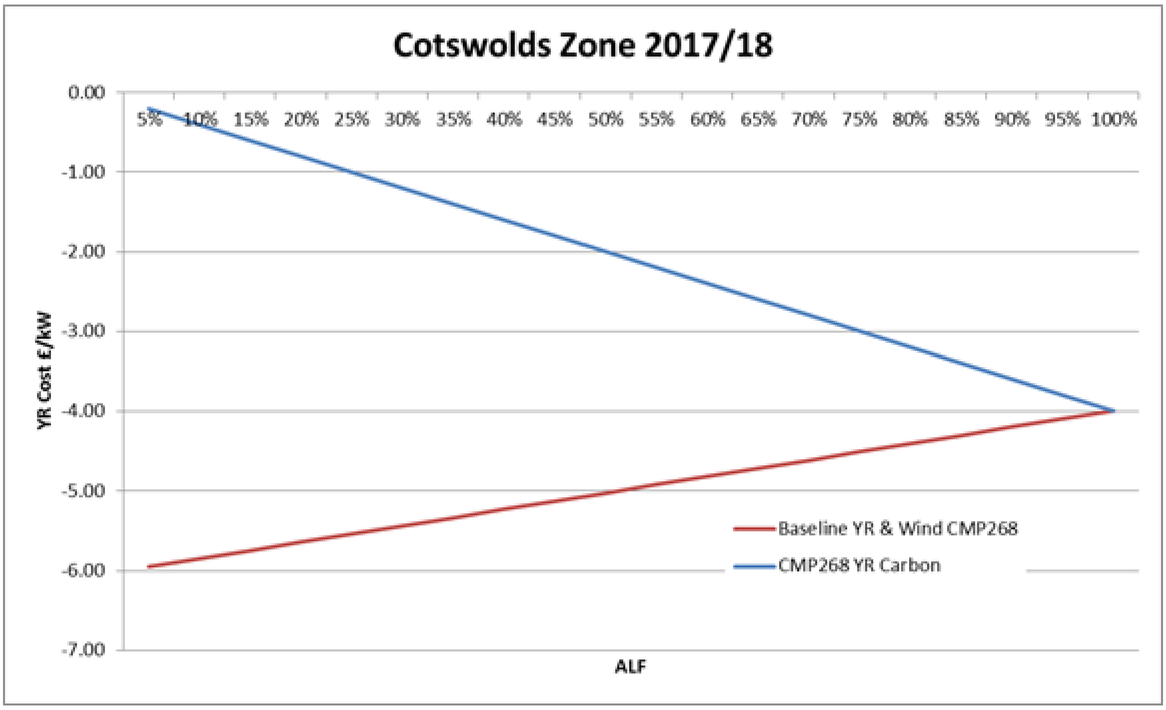


Figure 6

3.5.22 Therefore, this workgroup member felt that, not only would CMP268 provide undue preferential treatment to some stations in more northern zones, it would introduce incorrect incentives in parts of the network where you want to encourage plant to locate or remain to offset constraints.

3.6 CMP268 and generators in negative "not shared" zones

3.6.1 The workgroup discussed the effect of the proposed new methodology on Generators who currently have a negative Year Round Not Shared tariff.

3.6.2 National Grid provided an explanation of how the Year Round Not Shared tariff (YRNS) was calculated for a zone, and how a negative YRNS tariff may occur. The conclusion from National Grid was that it was due to the mathematical equation regarding the treatment of parallel boundaries rather than a lack of Diversity within the zone. No-one disagreed with this conclusion. All workgroup members agreed that CMP268 will have material negative impact on certain stations (Taylors Lane) who are forecasted to receive a benefit from a negative YRNS tariff. Adjusting the negative YRNS by Load Factor reduces the benefit, with the affect larger for those stations with low load factors (Taylors Lane) However some workgroup members argued that the negative impact on these stations, although not welcome may be justified as the 'benefit' they receive is due to a mathematical anomaly rather than intentional.

Workgroup members further views on negative YRNS Tariff

3.6.10 Workgroup members demonstrated a range of views regarding the question of whether the impact of CMP268 on the locational tariffs paid by Conventional Carbon generators in zones with genuinely negative Year Round "not shared" MWkm is cost reflective. It was noted that this question is not relevant for any existing charging zones, or any existing generators, however, it is possible that the question could become relevant sometime in the future. A workgroup member explained that cmp268 is cost reflective for negative YRNS zones for the following reasons:

3.6.11 With regard to the treatment of OCGT plant such for example Taylors Lane, it was the proposer's view that the workgroup could be described as exhibiting a majority view that for an OCGT with an ALF of zero, it would be cost reflective for that generator to pay a zero Year Round charge. The Proposer observed that CMP268 would deliver this result of a zero Year Round charge.

3.6.12 Different workgroup members reached this conclusion that an OCGT YRNS tariff should be zero for a range of different reasons including:

- Because their ALF is zero (irrespective of the fact that they are an OCGT as compared with a CCGT),
- Because the SQSS scaling factor for OCGT is zero (irrespective of what their ALF may be)
- Because the Not Shared Year Round charge should be zero for all conventional carbon generators (irrespective of their ALF, or classification as OCGT compared with CCGT).

3.6.13 Some workgroup members suggested that for higher load factor Conventional Carbon generators, the same economic principle which justifies applying the ALF to “shared” Year Round km also applies to “not shared” Year Round km. This is based on the economic reasoning that if a generator has a cheaper short run marginal cost, then it will tend to dispatch higher up the merit order, so it will tend to generate more of the time, so it will tend to have a larger impact on Year Round flows of electricity.

3.6.14 The proposer noted that there is no precedent for the ICRP Transport model, or Charging model to treat positive and negative costs or charges differently from each other. The approach taken by CMP268 to apply the ALF for Conventional Carbon generators to the whole Year Round tariff irrespective of whether it is positive, or negative, is therefore consistent with the approach.

3.5.15 Some workgroup members noted that regarding the treatment of Low Carbon plant in zones with a negative Not Shared Year Round CMP268 does not have any relevance because CMP268 does not make any change to the way the Year Round charge is calculated for plant classed as Low Carbon, therefore CMP268 is identical to Baseline in this regard. Further there are currently no Low Carbon generators located in any zones with a negative YRNS tariff, so this issue does not impact any existing Low Carbon generators.

3.5.16 The Workgroup agreed that further work outside the scope of CMP268 may be required to understand the rationale for sharing in negative zones.

3.7 SQSS Workgroup discussions following sendback by the Authority

3.7.1 The proposer provided a presentation to the Workgroup which summarised the previous analysis supplied to the Workgroup to date before the “send back”. This provided the Workgroup the opportunity to engage in further discussion of this evidence.

3.7.2 The proposer provided graphs (figure 7 to 9) which illustrated the TNUoS tariffs which would result from the Baseline and CMP268 methodologies and compared these with the tariffs which would arise from using the SQSS Economy Criteria scaling factors.

3.7.3 The proposer presented the case that the SQSS Economy Criteria scaling factors can be best understood as a form of “average” which uses a single scaling factor per technology type as a proxy to reflect an underlying distribution of individual generators as modelled by a full detailed CBA. When it comes to network investment decisions, the SQSS Economy Criteria scaling factors provide a first pass of likely network requirements, while final investment decisions for mitigating constraint cost are ultimately informed by a CBA. It follows that it is cost reflective for TNUoS charging to reflect this distribution whereby generators which cause a relatively higher cost should pay a relatively higher TNUoS charge while those generators which cause a relatively lower cost should pay a relatively lower TNUoS charge.

3.7.4 For the avoidance of doubt, it is explicitly not the claim of the proposer that it is cost reflective for every generator to face a TNUoS charge as close as possible to the SQSS “average” for their technology type. To the contrary, it is the Proposer’s position that it is more cost reflective for the distribution of TNUoS charges to reflect the distribution of different costs caused by different generators.

3.7.5 With regard to the Year Round Not Shared tariff element, Baseline treats all types of generators the same as each other with the same charge at 100% of TEC irrespective of its technology type, or its ALF. Therefore the Baseline application of the YRNS tariff does not reflect any distribution, or reflect any difference in the constraint cost, or associated network investment cost caused by different types of generator.

3.7.6 The proposer noted that CMP268 does treat different types of generator differently from each other in regard to the Year Round Not Shared tariff. This can be illustrated by considering the impact of CMP268 on tariffs paid by different types of generator compared with the SQSS scaling factors.

3.7.7 Some workgroup members suggested the following conclusions could be drawn from this impact analysis:

- For an OCGT with a very low, or zero ALF the Year Round TNUoS charge 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), CMP268 would result in a Year Round charge of at or close to zero £/kW. He Proposer argued that this outcome is consistent with the result of CBA analysis which is used out to inform network investment decisions and which is also used to inform the choice of zero scaling factor for this type of generation in the Economy Criterion of the SQSS. By contrast, Baseline would charge the YRNS tariff to OCGTs at 100% of their TEC in the same way as Baseline applies the YRNS tariff to any other type of generator such as a new entrant CCGT, or nuclear generator. Therefore for this type of low/zero ALF generator, CMP268 is clearly more cost reflective.

- For CCGTs, CMP268 will result in a range of different Year Round charges for individual generators which are distributed around the single charge indicated if the single technology type SQSS Economy Criteria scaling factor was used. This distribution of CCGT Year Round tariffs is a function of their ALF as a proxy for the different operating characteristics of each individual plant as modelled by a CBA. For example:

    - An old inefficient CCGT with operating characteristics like that of an OCGT will tend to exhibit a low ALF and tend to cause a low network investment cost like that of an OCGT. It follows that CMP268 is more cost reflective, because when a CCGT causes cost like an OCGT, then CMP268 charges it like an OCGT.

    - At the other end of the spectrum, for a high efficiency CCGT with a notional 100% ALF, then CMP268 provides the same Year Round charge as Baseline, so CMP268 is therefore no more, or less cost reflective than Baseline for a notional 100% ALF generator.

    - The Proposer suggested that it therefore logically follows that for CCGTs, since CMP268 is more cost reflective for low ALF stations and as cost reflective for high ALF stations, then it must therefore be more cost reflective overall for stations distributed within the range. The Proposer suggested this conclusion is consistent with the evidence that the network cost caused by Conventional Carbon generators associated with the Year Round tariff element is broadly proportional to their ALF.

- For the avoidance of doubt, the Proposer noted that it is the case that when a zone is fully shared (zero YRNS tariff), then CMP268 will result in the same tariff as Baseline, so it equally cost reflective in this regard.

- For Low Carbon generators (wind and nuclear), CMP268 does not identify any defect and does not propose any change, therefore CMP268 is the same as Baseline in this regard. Following CMP268, Low Carbon generators will continue to pay the YRNS tariff at 100% of their TEC which will drive a divergence in tariffs paid by Low Carbon compared with Conventional Carbon generators when there is an increasing concentration of Low Carbon generation.

3.7.8 **The graph below shows the tariffs for an OCGT which arise from Baseline, CMP268 and SQSS scaling factor.**

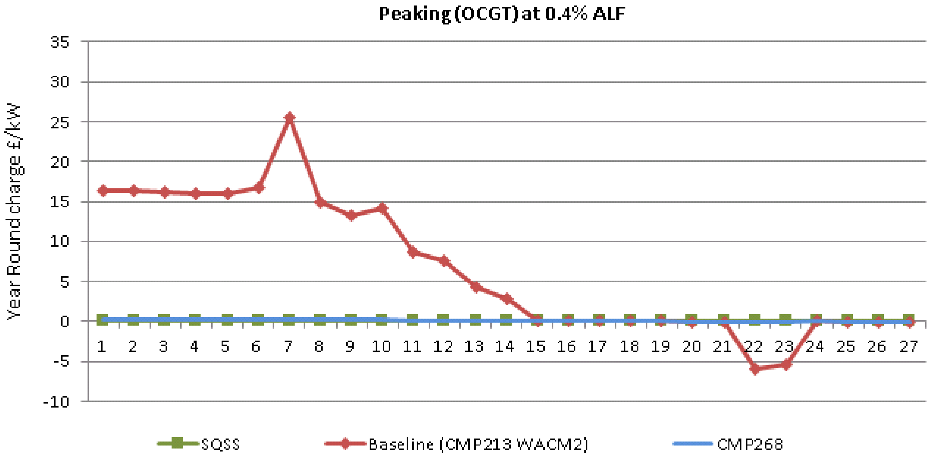


Figure 7

The graph below shows the tariffs for illustrative CCGT stations which arise from Baseline, compared with the SQSS scaling factor.

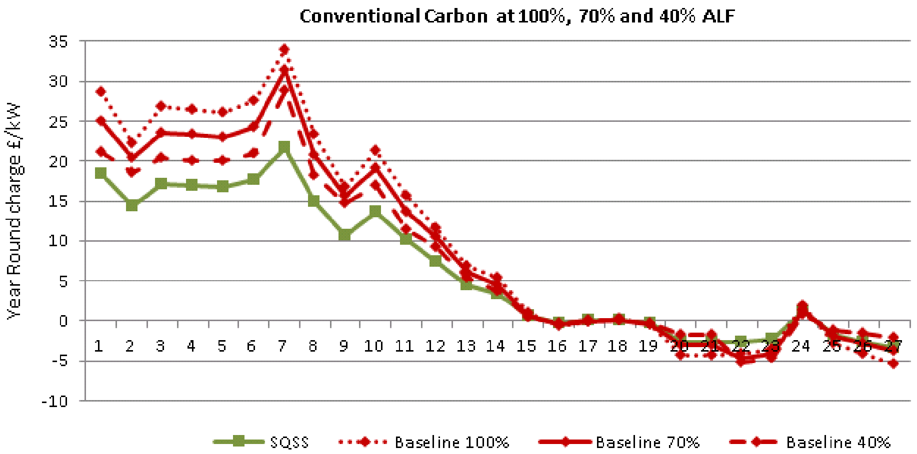


Figure 8

The graph below shows the tariffs for illustrative CCGT stations which arise from CMP268, compared with the SQSS scaling factor.

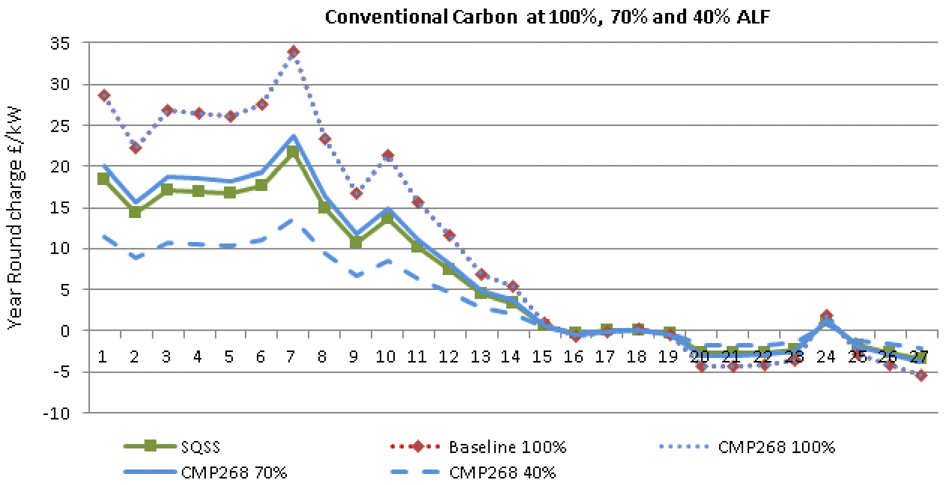


Figure 9

3.7.9 Some workgroup members noted that CMP 213 was designed to ensure that the charging methodology reflected how the transmission system was designed under the SQSS. ALFs are not used under the SQSS. Instead scaling factors are utilised which reflect the impact that different generation types have on network costs. Therefore, these workgroup members believed that there was a potential argument for using the SQSS factors rather than ALFs to achieve a more consistent solution than under CMP213 and CMP268.

3.7.10 A workgroup member noted that analysis had been undertaken by Uniper in its response to original code administrator consultation for CMP268. Uniper believed this analysis was more appropriate than similar analysis carried out by the proposer and which was recorded in sections 4.50 to 4.75 of the original Final Modification Report. The workgroup member agreed to summarise the analysis as it didn't seem to have been considered for the original modification report presented to Ofgem.

3.7.11 Uniper noted that the proposer's analysis plotted what the charge would be in different zones for different plant types if the SQSS factor was multiplied by both the shared and non-shared Year Round tariffs. It then compared this with the charges for the baseline methodology and CMP268 using various stylised ALFs. The graphs attempted to show that, for those ALFs, charges were closer to the SQSS under CMP268 than under the baseline.

3.7.12 The Uniper analysis used the actual ALFs which were used to set charges as Uniper felt that this would be more representative of the actual generation mix. To do this Uniper used the spreadsheet which National Grid provided as part of the assessment of CMP268. This already calculated the charges which would apply under the existing baseline and compared them with those under CMP268. The spreadsheet was used to calculate what the charges would be using the SQSS factors to scale both the shared and non shared Year Round charges as in the proposer's analysis.

3.7.13 Uniper then calculated the difference between the SQSS scaled charges and those under the existing baseline. The analysis also calculated the difference between the SQSS scaled charges and those under CMP268, in order to assess which methodology produced charges which were closer to those using the SQSS factors. The results of this are plotted in figure 10 below.

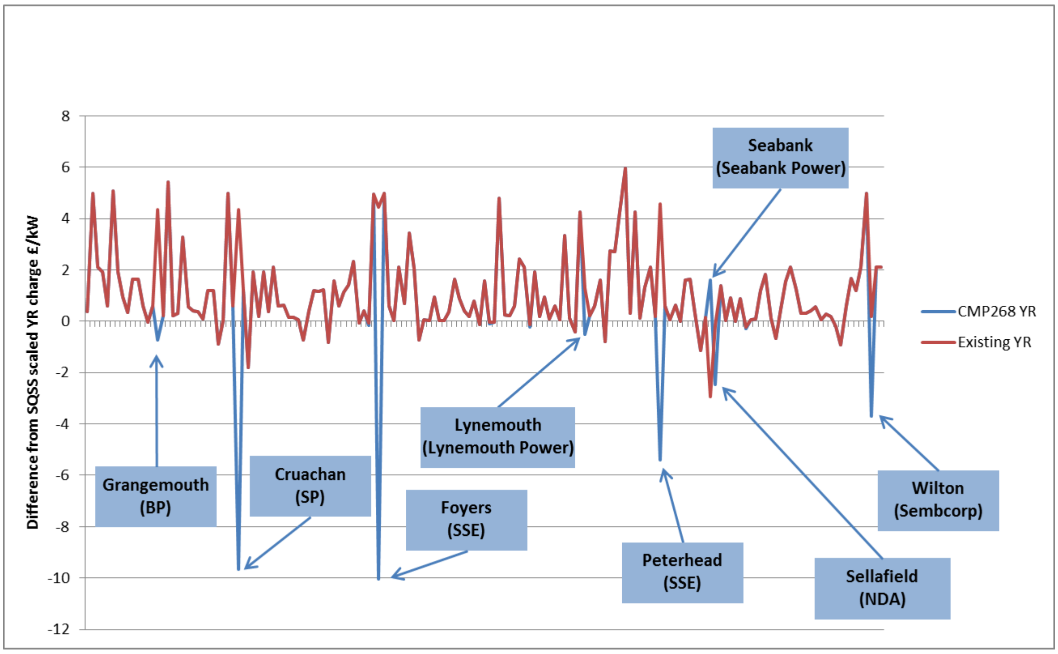


Figure 10: Difference from SQSS factor scaled YR charges, of charges calculated using Existing Methodology and CMP268

3.7.14 Uniper noted that the first thing that figure 10 shows is that the existing methodology tends to produce Year Round charges which are not the same as those using the SQSS factors. Of course, this is not surprising given that the SQSS uses a generation class average and the ALF is specific to a plant. Some charges are reasonably close, but this is likely to be caused by coincidence rather than by design. This is also true for CMP268 which again is unsurprising. Given the design of CMP268, the charges for most stations are the same as for the existing baseline, so the differences from the SQSS are also the same in these instances.

3.7.15 However, Uniper concluded that when CMP268 does produce different charges, it generally does not bring charges closer to the SQSS scaled ones, which would reduce the difference to closer to zero in the chart above. Instead, it tends to pull charges down significantly so that they are well below the SQSS scaled numbers. Therefore, Uniper concluded that if you were to assume that the SQSS scaled numbers are somehow a measure of what's fully cost reflective, then CMP268 appears to make the charges less so than the baseline

3.8 Conclusions

3.8.1 Some workgroup members viewed that the additional consideration of the impacts of CMP268 further support the conclusion that CMP268 does result in a set of tariffs which are more cost reflective and which also result in more cost reflective changes to tariffs when the generation background changes. Therefore the CMP268 methodology is more robust to changes in the future GB generation mix.

3.8.2 For those generators which are directly affected, CMP268 will result in relatively large changes in their TNUoS tariffs. Some workgroup members concluded that this illustrates the relatively large value of the defect and the relatively large value of the distortion to effective competition and discrimination caused by the defect in the Baseline methodology.

3.8.3 Some workgroup members considered that the additional analysis simply illustrated the change in tariffs and associated locational incentives that could result from the introduction of CMP268. These workgroup members concluded that there was no additional evidence that clarified the nature of the defect.

4 Additional Workgroup discussions

4.1 Introduction

4.1.1 This section describes the additional workgroup discussions within the following sections:

- CMP268, SQSS scaling factors and Transmission Investment
- The ALF as a proxy for a Cost Benefit Analysis
- Discussion of whether it is appropriate in principle to apply a sharing factor to the YRNS tariff element
- Discussion of implications of averaging

4.2 CMP268, SQSS scaling factors and Transmission Investment

4.2.1 The workgroup discussed the relationship between the charging methodology and the scaling factors used in the SQSS.

4.2.2 The SQSS uses fixed scaling factors for certain classes of plant[2]. The scaling factor for wind, wave, or tides is 0.70. For “conventional carbon generators” *registered capacity* is scaled such that their aggregate output is equal to the forecast *ACS peak demand* minus the total output of directly scaled plant.

4.2.3 The workgroup discussed the relationship between the charging methodology and the scaling factors used in the SQSS. The SQSS scaling factors are derived from a cost benefit analysis that considered different conditions on the transmission system under the peak and economy (year round) background.

4.2.4 It was the view of some Workgroup members that the SQSS determines the minimum criteria for investment in the transmission system.

4.2.5 It was noted that the scaling factors do not represent load factors. The scaling factors are applied to the capacity of classes of plant. The scaling factor is significantly different from the actual (operational) load factor for individual plant and different from the Annual Load Factor (ALF) derived from historic data in the charging methodology.

4.2.6 The scaling factors are used in the charging methodology (the Transport Model) as the basis for identifying the nodal MWkm in the Peak and Year Round Background. These nodal MWkm are assigned to generation zones using the zoning criteria. The zonal MWkm are multiplied by the Expansion Constant and the Security Factor to derive a set of zonal Peak and Year Round tariffs. The charging methodology sets out an approach to sharing the year round tariff based on the diversity of generation in a zone between

[2] For nuclear stations, and for coal-fired and gas-fired stations fitted with Carbon Capture and Storage, scaling factor (DT) = 0.85 ; For pumped storage based stations, DT = 0.5; For interconnectors to *external systems* regarded as importing into GB at the time of peak demand, DT = 1.0; There are also a set of “non- contributory” generation and this plant, such as OCGTs, does not form part of the generation year round background

"carbon" and "low carbon" which results in a "shared" year round tariff and a "non-shared" year round tariffs. The "shared" tariff is applied to individual generating capacity according to its Annual Load Factor and the "non-shared" tariff is applied to the TEC of all plant.

4.2.7 The basis for the utilisation of the ALF in the charging methodology was first set out in CMP213. Under this proposal it was suggested that for the year round tariff he ALF better represented the investment drivers than the transmission capacity of individual plant. The original proposal therefore suggested the use of ALF for the year round tariff. However, this approach was challenged in the CMP213 working group and an alternative approach was developed and ultimately adopted as a Working Group Alternative (WACM1) (see below).

4.2.8 Under CMP268 some members of the workgroup had the view that the evidence supports the position that the ALF better represents the actual driver of investment rather than the scaling factor for conventional carbon generators. However other members of the workgroup suggested that the scaling factor could be considered to be a better and more cost reflective basis for setting the year round tariff.

4.2.9 It was noted by the working group that scaling factor approach was debated under CMP213 and was not taken forward as an alternative. Ofgem ultimately approved WACM1 which included the sharing methodology. Therefore some other members of the work group believed that use of scaling factors was outside of the scope of the defect for CMP268. Within the CMP268 Workgroup, there were no alternative proposals forwarded by any Workgroup members regarding the use of scaling factors.

4.2.10 It was the view of some Workgroup members that the charging methodology does not take into account any individual cost benefit analysis for specific transmission investments. Rather the charging methodology recognises the need to meet the investment criteria under the SQSS and through simplifying assumptions introduces the concept of sharing in order to reflect the trade-off between constraint costs and investment in the application of the tariffs. Therefore the issues associated with specific cost benefit analysis were outside the scope of CMP268.

4.3 The ALF as a proxy for a Cost Benefit Analysis (CBA)

4.3.1 A second National Grid Representative from the National Grid Network Investment Team delivered a presentation to the Workgroup describing the how Cost Benefit Analysis is used in the process of making network investment decisions.

4.3.2 The evidence provided by this National Grid Representative from explained the different stages involved in making network investment decisions including the SQSS, Electricity Ten Year Statement, Network Options Appraisal process, Strategic Wider Works process and TO licence condition that investment decisions should be economically efficient. CBA analysis is used to evaluate what network reinforcement would be economically efficient given a particular portfolio mixture of generation assets and demand across a range of potential future market scenarios. This explained investment decisions associated with the SQSS Economy Criteria are ultimately driven by a requirement to be economically efficient as reflected by a detailed cost benefit analysis.

4.3.3 This National Grid Representative from explained the steps involved in network investment planning include:

Step 1: SQSS is designed to be broadly cost reflective of the result of detailed Cost Benefit Analysis and is updated from time to time to ensure it remains appropriately cost reflective. The SQSS is a "first-pass" assessment of the likely optimal capacity requirements.

Step 2: Electricity Ten Year Statement (ETYS) – Shows likely future transmission requirements of bulk power transfer capability of the NETS. This identifies potential deficits in the existing network capability.

Step 3: TOs develop options for network reinforcement

Step 4: Detailed Cost Benefit Analysis (CBA) modelling

a) Network Options Appraisal (NOA) – Uses CBA modelling approach to carry out an economic assessment of options the TOs have provided for meeting GB system requirements. Identifies the options that the SO recommends as being economically justifiable for the TOs develop further this financial year.

b) Strategic Wider Works mechanism – Uses CBA modelling approach. Once a Strategic Wider Works (SWW) needs case has been approved by Ofgem, the option is excluded from the NOA analysis although the report refers to it and it is included in the baseline. This is because it is managed through the SWW process

Step 5: TOs develop detailed investment proposals - TOs Make use of all information already available plus additional technical and engineering analysis and design detail. TO must be able to make the case to Ofgem that the proposals are economically efficient.

Step 6: Final investment decision

a) If investment is small - TO makes the decision. TO license condition requires investment decisions to be economically efficient. Economic case largely driven by the CBA carried out during the NOA analysis.

b) If investment is big (high cost, or if classed as SWW) – Ofgem makes decision regarding the eligible cost of the reinforcement. Economic rationale based on CBA analysis.

TO still makes final investment decision, but is unable to invest if Ofgem has not approved the budget.

Step 7: Charging arrangements – Element which charging should be cost reflective of is the "final investment decision". It achieves this by drawing on the most appropriate elements of both SQSS and CBA structures.

4.3.4 A presentation provided to the Workgroup by the National Grid Representative explained that within the CMP213 solution, the purpose of the Peak Security and Year Round backgrounds are different. Some workgroup member's interpretation of this was that it explained that it is only the Peak Security background which reflects investment planning on a deterministic basis, while the purpose of the Year Round background is to be a proxy for the result of a full cost benefit analysis. The presentation also explains that within CMP213, the purpose of the ALF as a measure of load factor is to reflect the impact of an incremental MW of generation on SRMC (constraint cost) as calculated by a full cost benefit analysis. This conclusion is supported by the following quote from the presentation which was provided to the Workgroup (CMP213 – Workgroup Meeting 2, National Grid, 24th July 2012):

- "Background split into Peak Security (PS) and Year Round (YR)
- PS planned on a deterministic basis
- ➢ Associated charges remain capacity based
- YR is a proxy for full cost benefit analysis
- ➢ Utilise convergence of LRMC and SRMC over long term
- ➢ In Theory: Impact of MW on SRMC = impact of MW on LRMC
- ➢ Demonstrate: Load factor reasonably representative of impact of MW on SRMC"

4.3.5 The proposer explained that the question of whether to use ALF, or generic SQSS scaling factors was previously considered during CMP213 and the decision was reached during CMP213 that the use of ALF was better than using generic SQSS scaling factors. The proposer explained that the rationale at the time of CMP213 was that the ALF better reflected the different cost caused by the different operating characteristics of specific individual plant and that since these individual differences can be measured, it would be discriminatory to treat them as if they were the same as each other by using generic technology type scaling factors. CMP268 is fully consistent with CMP213 in this regard. This conclusion is described in the following quote from the CMP213 FMR:

"*4.104 The [CMP213] Proposer restated that* ***the reason ALF was being used under the Original was that it was a proxy for the effect that a specific generator has on transmission system investment****. It was recognised that whilst the generic scaling factors under GSR009 provided a suitable background for assessment, specific generators of a* *common technology could cause significantly different impacts on transmission investment based on their level of output over a sustained period. Hence, under the Original proposal ALF would be a longer term, plant specific annual load factor rather than by generation type*."

4.3.6 The Proposer believed that the CMP213 conclusions suggesting that the ALF was a better proxy for an individual cost benefit analysis than the current baseline was a significant factor in CMP268. In their view, for Conventional Carbon generators, using the ALF applied to the Not Shared Year Round component of the tariff was as a result more cost reflective.

4.3.7 Some workgroup members suggested that the charging methodology does not explicitly take into account any individual cost benefit analysis for specific transmission investments. Rather the charging methodology recognises the need to meet the investment criteria under the SQSS and through simplifying assumptions introduces the concept of sharing in order to reflect the trade-off between constraint costs and investment in the application of the tariffs. Therefore for these workgroup members the issues associated with specific cost benefit analysis and associated transmission investment were outside the scope of CMP268.

4.4 Discussion of whether it is appropriate in principle to apply a sharing factor to the YRNS tariff element

4.4.1 The workgroup discussed whether it was appropriate to ALF to the year round not shared tariff element.

4.4.2 Some workgroup members suggested that given the nature of the CMP268 defect it would be appropriate to reconsider the work undertaken as part of CMP213. This could include the nature of constraint costs for different types of generator and the nature of the boundary sharing factor. However, the proposer relieved that these elements were out of scope.

4.4.3 There was a difference of opinion as to whether the not shared element of the year round tariff could be shared with respect to conventional carbon generators. Some members of the workgroup believed it could be shared in this class of generator, while others believed that if could not be shared. It was noted that the shared element of the tariff already provides low load factor plant with reduced year round tariffs.

4.4.4 It was suggested that that if there is an issue caused by the approach taken for the drivers of constraint costs under CMP213, the solution is to look at these as a whole and devise a solution to locational charging which seeks to reflect these more accurately. For example, the analysis could consider:

- The underlying relationship between the SQSS and the sharing methodology and the drivers for investment;
- the effects of each node on transmission investment and the incremental constraint costs;

- the underlying relationship between different classes of generator in the zone and the boundary sharing factors;
- the underlying relationship between individual generators in the zone and the constraint costs;
- the flows across transmission boundaries as implied under the sharing methodology used to allocate the shared and not shared component of the tariff;
- the boundary sharing factor threshold of 50%; or
- the application of the scaling factors derived from the SQSS.

4.4.5 A workgroup member suggested that, CMP268 does not address the fundamental basis for setting the tariffs under CMP213 WACM1. Rather they suggested that it seeks to take the outputs from the sharing methodology and simply relieve certain generators from certain obligations to pay the not-shared component of the tariff. Certain workgroup members did not believe that the evidence under CMP213 was sufficient to justify such an exemption and that such an approach was essentially arbitrary.

Table 7: Treatment of generator class under the baseline and CMP268

	Baseline		CMP268	
	Shared	Not Shared	Shared	Not Shared
“Conventional Generation”	ALF * Capacity	TEC	ALF * Capacity	ALF (or N/A*)
“Intermittent Generation”	ALF * Capacity	TEC	ALF * Capacity	TEC

** Amended by the proposer from ALF to not applied, see below*

4.4.6 It was noted that the proposer believed that such different treatment was justified since it reflected their view of the relative constraint costs for certain classes of generator. Other members of the workgroup did not believe that such different treatment could be justified

4.4.7 The proposer noted that a Workgroup member claimed that it was wrong in principle and inconsistent with the principles of CMP213 to apply the ALF to the YRNS tariff element because in their view the YRNS tariff element is by definition not shared, so cannot be shared. Also as described above, other Workgroup members suggested that the true root of the defect may be better addressed by making changes to the Transport model, or Charging model instead. The Proposer noted that similar issues were also suggested in the RWE paper submitted to the Workgroup and attached in Annex 4. The Proposer responded to these issues with the following comments:

4.4.8 The Proposer suggested that it is not a valid criticism to claim that a solution is inconsistent with the principle of how the “Not Shared” tariff element is treated in Baseline when this criticism directly relates to the specific feature of Baseline which the proposal has specifically identified as a defect and proposes to change. Logically, any proposal has to provide a solution which is different from Baseline as an essential part of identifying a defect and proposed solution within the CUSC.

4.4.9 The Proposer noted that the key factor for determining whether a modification proposal is, or is not appropriate is the applicable CUSC objectives and with respect to this modification proposal, in particular whether it is more cost reflective than Baseline. The proposer therefore suggested that the question of cost reflectivity takes precedence over other issues of whether the change may, or may not be consistent with the way the Baseline methodology currently works, or whether the change may or may not directly affect only a small number of generators.

4.4.10 The Proposer noted that the point of the defect identified by CMP268 is that different types of generator (i.e. Conventional Carbon generators compared with Low Carbon generators) cause different costs, so in order to be appropriately cost reflective, the charges paid by these two different types of plant must be different from each other. It follows that any attempt to change some aspect of sharing which would continue to treat these two different types of generator as if they are the same as each other would fail to address the defect. The Proposer therefore argued that alternative solutions suggested by the Workgroup listed above and referred to in the RWE “Cost Reflectivity Paper” would fail to address the defect.

4.4.11 The Proposer suggested that it is a generally accepted principle of discrimination that it can be discriminatory to treat alike things differently and it follows that it is also discriminatory to treat things which are different from each other as if they were alike. It follows that the approach of CMP268 to treat a subset of Conventional Carbon generators differently from Low Carbon generators is not discriminatory because this difference in treatment is based on a difference in the cost which they cause. To the contrary, the question of discrimination arises if the charging methodology failed to recognise this difference as is the case with the current Baseline

4.4.12 The Proposer noted that the current Baseline methodology already uses the ALF to reflect incremental cost in situations where a particular generator is obtaining a full sharing benefit in their use of the network. This specific feature of the ALF is not identified as a defect by CMP268 and CMP268 is not proposing any change to the Baseline in regard. The change which CMP268 proposes to make is the recognition that network costs reflected by the YRNS tariff element are in fact fully shared by Conventional Carbon generators. By contrast, CMP268 does not make any change to the Baseline principle that for the incremental cost of elements which have been identified as fully shared, this sharing should be reflected by the ALF.

4.4.13 The proposer noted that CMP268 reflects the obvious principle that sharing can be asymmetric. This means that when two parties are using the same network, each party can exhibit a different degree of sharing benefit with regard to the different capacity of the network which is required in order to accommodate an incremental change in their use of it. It is therefore not a logical argument to suggest that just because an element of the tariff is not shared by some types of generator that it necessarily can not be shared by any type of generators.

4.4.14 The Proposer noted that CMP268 provides a solution for the treatment of the Year Round tariff element which, for Conventional Carbon generators, is exactly the same in its effect as the CMP213 Original which was previously proposed and supported by National Grid. This is because for this specific type of generator, CMP268 and CMP213 Original both propose to apply the ALF to the whole of the Year Round tariff,

4.4.15 The Proposer suggested that CMP268 is a natural extension of Baseline as developed by CMP213 and CMP268 does not reverse or undo any explicit decision regarding cost reflectivity made during CMP213 with specific regard to Conventional Carbon generators. In CMP213, the Year Round Not Shared tariff element was designed to reflect the additional cost caused by expensive bid prices from Low Carbon generators. The CMP213 FMR recognised that within the Diversity 1 approach which became WACM2, that Conventional Carbon generators would be affected by this alternative to the CMP213 Original in a way which was not cost reflective for those Conventional Carbon generators. However in the interest of balancing the objectives of further improving cost reflectivity compared with adding complexity, the CMP213 workgroup did not pursue any further a particular solution to this remaining defect for Conventional Carbon generators at that time. CMP268 therefore picks up where CMP213 Workgroup left off to identify a more cost reflective additional feature specifically for Conventional Carbon generators which does deliver a better solution with regard to balancing improved cost reflectivity compared with increased complexity. This was described in the CMP213 FMR as follows:

> "*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*." (CMP213 Final CUSC Modification Report Volume 1, para 4.70)

4.4.16 The Proposer noted that the same Workgroup member who claimed that it is not appropriate as a matter of principle to apply any adjustment factor at all to this tariff element to reflect different degrees of sharing also supported the position that it is appropriate in principle to use the SQSS scaling factors as an adjustment factor to the YRNS tariff element. The Proposer suggested that these two positions are contradictory and mutually exclusive. That same Workgroup member and others also took the view that it is appropriate in principle to apply a zero adjustment factor to the YRNS tariff for OCGT generators with the particular justification that this is the scaling factor used for this type of generation in the SQSS. It follows that that there were wide spread views on the workgroup that it is appropriate in principle to apply an adjustment factor to the Year Round Not Shared tariff element for some types of generator which is different from other types of generator and which is different from the Baseline level of 100% in order to better reflect the different contribution to cost associated with the YRNS tariff element made by different types of plant.

4.4.17 The Proposer suggested that the term “Year Round Not Shared” is simply a label used for descriptive purposes and the choice of name itself does not override the CUSC applicable objective of cost reflectivity. It is therefore not a logically valid argument to claim that the Year Round Not Shared tariff can not be shared simply because the words “not shared” are in the name. It was suggested that if there was an issue created by the phraseology of the name of the “Year Round Not Shared” tariff element, then it may be helpful to consider using a different name such as “Year Round Partial Shared”, however, this option to change the name was not pursued further by the Workgroup. It is important to note that the choice of name of this tariff element whether it remains the same, or may be changed, does not change the economic merits of the CMP268 proposal.

4.5 Discussion of implications of averaging

4.5.1 The workgroup discussed the nature of sharing methodology for the year round tariff.

4.5.2 One workgroup member noted that CMP213 WACM1 reflects the average constraint costs for generation classes and the diversity of plant in a zone. It was emphasised by a number of Workgroup members that this form of averaging used in developing the current charging methodology results in generators that from the charging base pay the relevant tariffs on a non-discriminatory basis. This means that all generators in a zone pay the shared component of the tariff based on ALF and all generators in a zone pay the not-shared component of the tariff based on their TEC. Under CMP 268 conventional generation will no longer pay the not shared component on the same basis as other generators in that zone.

4.5.3 It was noted that there were a number of simplifying assumptions used such as the categorisation of generation into carbon and low carbon, reflecting different constraints costs for different types of generation, the use of a 50% sharing factor and the application of the sharing factor across a number of zonal boundaries. In addition, the tariffs are applied to all generators in a zone based on averaging the outputs of the Transport Mode (in MWkm) and allocating these MWkm into “shared” and “not shared” MWkm.

4.5.4 Some members of the workgroup argued that as a result of these simplifying assumptions it was not appropriate to assume that the not shared element of the tariff could be shared for conventional generation according to its ALF. However, further work on the nature of sharing itself could be required to understand whether it was appropriate to share this element of the tariff. However this was out of scope for the workgroup.

4.5.5 It was the view of some workgroup members that CMP268 does not unwind any form of averaging, as described below in more detail. However, even if it unwind some form of averaging, then this would not be a problem for CMP268 as long as it was more cost reflective to do so.

4.5.6 The Proposer explained the position that the development of the YRNS tariff averaging took account of the average incremental constraint cost caused by plant classed as Low Carbon only (specifically wind). By contrast, the incremental constraint cost caused by plant classed as Conventional Carbon plant was not part of this averaging process. It follows that CMP268 does not change the result of this (or for the avoidance of doubt any other) form of averaging calculation used in the charging methodology

4.5.7 Some working group members felt that there are fundamental differences between the approaches for CMP213 and CMP268 when it comes to the treatment of diversity.

4.5.8 These working group members believed that the different treatment of diversity under CMP213 was to reflect the differing likelihood that the system operator would be able to access lower cost bids when managing constraints. This was to reflect the breakdown of the observed relationship between ALF and constraint cost in the modelling undertaken for CMP213 as outlined in the presentation given by National Grid’s representative on the CMP213 working group. These members noted that a simplified average approach was adopted which reflected that fact that as the proportion of low carbon plant increased, or the proportion of carbon plant reduced, then the likelihood of accessing lower cost bids reduced.

4.5.9 These workgroup members noted that in reality the drivers of constraint costs are more complex than simply the load factor of a station. Other factors such as the coincidence of running at times of constraints, the merit order of plant available for bids and offers affect costs too. However, the approach taken for CMP213 was to simplify the relationship to one related to load factor of the plant alone.

4.5.10 Therefore, these workgroup members believed that, under CMP213:

1. The load factor of the plant was supposed to reflect the volume of constraints caused by plant; and
2. The shared and not shared tariff split was intended to reflect the higher likely cost on average of solving those constraints

Therefore, there was no need to allocate specific likely costs to particular plant types. It was assumed that similar load factor would drive similar volumes of constraints regardless of the plant type, for example due to the simplified solution not considering whether plant generated more at times of constraint. Similarly, CMP213 did not consider the merit order of plant at times of constraints for particular plant types.

4.5.11 These workgroup members felt that CMP213's approach to diversity could be summarised as follows:

Diversity level	**Treatment of all plant**
High	You are more likely to be able to use bids of carbon plant to address constraint volumes, due to high diversity, so scale more of the asset costs based on ALF.
Low	You are less likely to be able to access carbon plant bid prices to address constraint volumes caused by increase in capacity, due to low diversity, so you should build to meet closer to 100 percent installed capacity, so scale less of the asset costs based on ALF

4.5.12 These workgroup members felt that CMP268 was moving away from this simplified average approach towards one that specifically looked at the particular impact that specific plant could have on constraint costs. This meant that carbon plant would be treated more favourably than low carbon plant under the arrangements as it would be assumed that this is always able to bid off at lower cost bid prices. That is, diversity should not seek to reflect the likelihood of accessing lower cost bids in general, but should look at the specific impact of plant in a fully marginal sense. These workgroup members believed CMP 268's approached to diversity could be summarised as follows:

Diversity	**Carbon Plant**	**Low Carbon Plant**
High	You can use lower cost bids to address the constraint volumes caused by the additional carbon plant capacity	You can use lower cost bids address the constraint volumes caused by the additional low carbon plant capacity
Low	You can use lower cost bids to address the constraint volumes caused by the additional carbon plant capacity	You cannot use lower cost bids address the constraint volumes caused by the additional low carbon plant capacity

4.5.13 These workgroup members believed that if this more specific marginal approach was to be explored, that this would need a more fundamental review of the arrangements introduced under CMP213, to apply on a consistent basis to all plant and reflect all relevant characteristics such as load factor, coincident running with times of constraint, and bid/offer prices of plant. These workgroup members believed that in seeking to only apply this different approach to carbon plant there would be an inconsistent treatment between low carbon plant (which would continue to be subject to the averaging treatment under the present averaging arrangements, including the effects of carbon plant) and carbon plant (which would be exposed to a specific treatment). These workgroup members believed that, notwithstanding any other concerns they had about the modification, the solution for CMP268 would introduce discriminatory treatment as a consequence.

5 Amendment of CMP268Solution

5.1 The workgroup considered potential alternative proposals but none were formally taken forward as Workgroup Alternative CUSC Modifications. Therefore discussion in this section should be regarded as for information only.

5.2 Following a number of meetings that were held following the send-back decision from the Authority the Proposer requested if they could change their solution. However the CUSC Panel made the judgement a variation of the proposal would not be allowed due to the regulations governing the "send back".

5.3 This section describes the Proposer's rationale for a potential alternative solution.

5.4 For the avoidance of doubt, it is the proposer's view that the Original proposal is clearly substantially better than Baseline particularly with regard to better cost reflectivity and more effective competition; it is also theoretically consistent with the economic principles behind the CMP213 Baseline methodology. The Original proposal to apply the ALF to the YRNS tariff remains the best cost reflective solution if Conventional Carbon continues to generate during periods when constraints occur. In this scenario, Conventional Carbon generators may continue to be constrained off at a relatively low cost to the System Operator due to their relatively inexpensive bid prices and in this way they continue to cause an incremental cost of constraints, therefore incremental cost of network investment which remains proportional to their ALF applied to both the YRS and YRNS elements of the tariff.

5.5 However, over the course of Workgroup discussions following "send back", it became clear that a potential alternative solution may present the possibility of a further improved solution. This potential alternative was based on the position that when an area becomes increasingly dominated by Low Carbon generation, then the incremental cost caused by Conventional Carbon may reduce below the value of their ALF. This reduction in the incremental constraint cost caused by Conventional Carbon generators would be because they may tend to exhibit a reduction in their generation during periods in which constraints are taking place as represented by a reducing availability of bid prices. It would clearly follow that if a Conventional Carbon generator is not generating during a period when a constraint is occurring, then that Conventional carbon generator is not causing any cost at all with regard to either the cost of managing those constraints, or the cost of network reinforcement required to manage those constraints. It follows that if Conventional Carbon generators are not causing any cost at all in this regard, then it would be appropriate that the TNUoS tariff they pay should reflect this. If this situation occurs, then it may be better reflected by Conventional Carbon plant not paying the Year Round Not Shared tariff element at all.

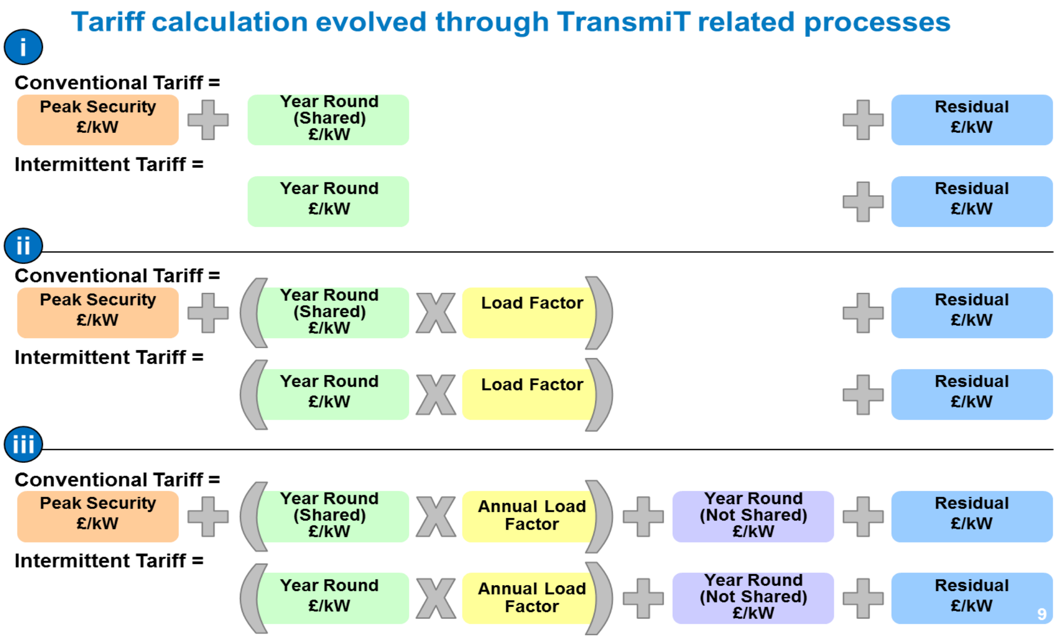
Proposers section on discussions around the potential amendment to the solution

5.6 The Original proposed solution recognised that as diversity reduces as the proportion of low carbon increases beyond 50%, it is only Low Carbon generators which drive an increase in the incremental cost of constraints which they cause, while by contrast, Conventional Carbon generators are different because in this situation they do not drive an increase in the incremental cost which they cause.

5.7 This potential alternative to the CMP268 Original solution would go one step further than the Original by recognising that as low carbon generation proportion increases beyond 50%, the incremental cost caused by Conventional Carbon generators instead of being the same as that caused by when Low Carbon proportion was less than 50% (i.e. proportional to ALF), actually reduces.

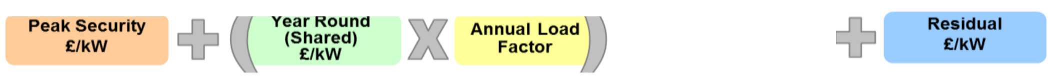
5.8 The potential alternative solution related to the way the Year Round Not Shared tariff is charged by looking to charge Low Carbon Generation the Year Round Not Shared element of the tariff based on their TEC (i.e. the same as current baseline), but not charge Conventional Carbon this element of the tariff at all as shown in the diagram below.

5.9 The graphic below illustrates the potential alternative solution in the context of the incremental development of the methodology illustrating that this is an incremental next step in the development of the charging methodology.



5.10 Incremental change of CMP268 varied solution specifically for Conventional Carbon generators is shown below, while other types of generator remain the same as "iii" above:

(iv) Conventional Carbon tariff =



5.11 For the avoidance of doubt, this alternative proposal would not make any change to the way the baseline uses ALF to reflect sharing. It also would not change the way the Year Round tariff is calculated and it would not change existing generator classifications. The only feature which it would change is the formula by which the Year Round tariff is applied to different types of Conventional generator.

5.12 The request to vary the proposal arose from further consideration of the evidence and further discussions within the Workgroup. This used the following rational described in further detail below with the key question being "what is the most appropriate and cost reflective adjustment factor to apply to the Year Round Not Shared tariff element for Conventional Carbon generators?"

5.13 It is clearly not cost reflective and not appropriate in principle to use the same 100%xTEC adjustment factor for both Conventional Carbon and Low Carbon as per Baseline. Baseline is not cost reflective in the way that it treats Conventional Carbon and Low Carbon as if they were the same as each other with regard to the Year Round Not Shared tariff element. The evidence is clear that Conventional Carbon generators do cause a different and diverging costs compared with Low Carbon generators in respect to costs reflected by the Year Round Not Shared tariff element. These two types of generator are clearly different in this respect and it is therefore clearly not cost reflective for the Baseline to charge these two types of generator as if they were the same as each other.

5.14 This result was consistently demonstrated by evidence from a range of different sources as described in the Original CMP268 FMR submitted before "send back". This result was further confirmed in Workgroup discussion after the "send back" through the presentation to the Workgroup by the National Grid National Grid Representative from CMP213 Workgroup and also in the new economic modelling carried out by National Grid as described above.

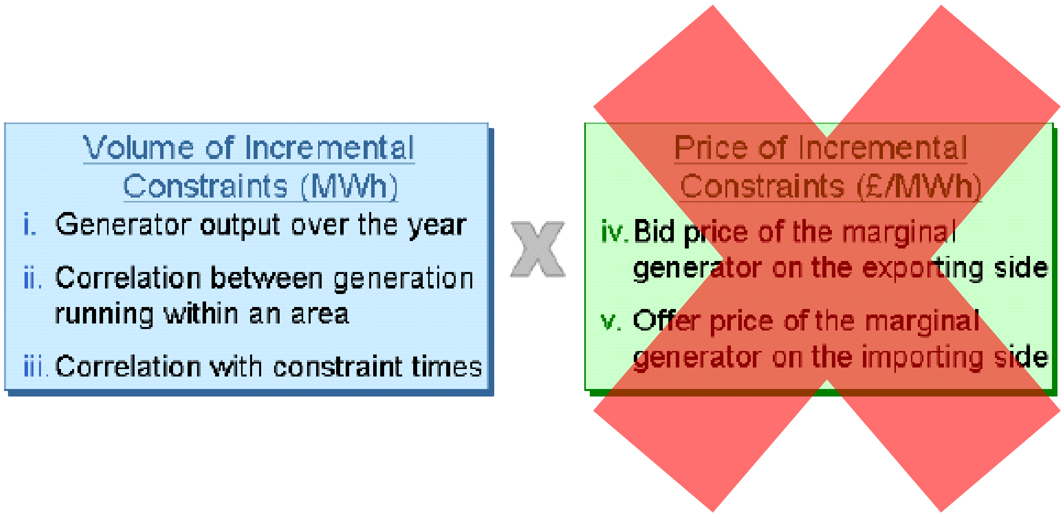
5.15 The potential alternative solution could be justified by economic principles and in particular the economic principle behind the Baseline treatment of bid prices with regard to the YRNS tariff within CMP213. This issue is explained in detail in the CMP213 FMR, CMP268 FMR and was repeatedly discussed in CMP268 Workgroup discussions and consultation responses. The quote below from Uniper's Workgroup consultation response is an example of this:

> "*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."*

5.16 Following CMP213 Project TransmiT, the principle is that the Year Round Not Shared tariff represent situations where the cost of constraints increases because of a reducing availability of bids from Conventional Carbon plant. Therefore, it would appear to follow that for the costs reflected by the Not Shared Year Round tariff, there is reducing generation from carbon plant to take bids from, therefore with regard to this particular element (i.e. Year Round Not Shared tariff element), the Conventional Carbon plant may be causing a reduced cost.

5.17 The key economic principles relevant for this potential alternative solution are illustrated in the picture below from the CMP213 FMR. This outlines the economic principles which determined the cost of constraints caused by different types of generator. This shows that for each generator, this cost is a function of the "volume of incremental constraints" they cause multiplied by the "price of incremental constraints" they cause. It would follow that if the "correlation with constraint times" reduces (i.e. they are less likely to be generating as demonstrated by reducing availability of bids), then the volume of incremental constraints they cause would reduce and therefore that the cost of incremental constraints which they cause would also reduce.

5.18 It would follow that if Carbon plant are less likely to be running at those times when constraints are occurring, then the bid price of Conventional Carbon plant becomes less relevant, as illustrated below



5.19 This reducing availability of bid prices occurs because when there is a higher concentration of Low Carbon generation, this is likely to tend to cause the timing of constraints to become increasingly correlated with periods which exhibit a combination of relatively high wind and relatively low demand. This is because as diversity reduces, constraints are likely to become increasingly concentrated in periods with a combination of "high wind"+"low demand", which tends to be low wholesale price periods which Conventional Carbon generators naturally avoid). Because Carbon generator output tends to be naturally inversely correlated with these types of periods (high wind and low demand), it therefore follows that when there is a higher concentration of Low Carbon generators, then Carbon generators will likely in turn tend to become increasingly inversely correlated with periods of constraint i.e. they will tend to become progressively less likely to be generating when constraints are happening.

5.20 This solution would recognise that there may continue to be periods when Carbon plant are available to provide bids for managing constraints, the cost which will continue to be reflected by their ALF applied to the Year Round Shared element of their tariff. In this regard, the proposed solution does not make any change and therefore remains identical to Baseline.

5.21 This result is also consistent with the CMP213 principles applied to the Peak Security tariff element:

- CMP213: Intermittent may use the network at peak times, but it does not cause the cost reflected by the Peak Security tariff, so Intermittent generation should not pay this element of the tariff.

- CMP268: Conventional Carbon may on occasion use the network at the same time as Low Carbon, but if Conventional Carbon does not cause the cost reflected by the YRNS tariff element, then Conventional Carbon generation should not pay this element of the tariff.

Comments from other workgroup members

5.22 A Workgroup member claimed that despite the change in the solution that they continued to not believe there to be a defect in the Charging Methodology. The member went onto claim that should there be a defect that it would be in a different area of the Methodology and that it could not be rectified with just dealing with the ‘symptoms’ of the defect. Another Workgroup member claimed that in order to look at the Charging Methodology, that is applied using averaging, you would have to look at the whole picture rather than a subset and then charge them differently. The member claimed that this would be discriminatory.

5.23 One Workgroup member stated that it was not appropriate for all Conventional Carbon to be treated in this way, but that it would make sense for an OCGT to be treated in this way due to the SQSS scaling factors and they, therefore could be exempt but that was not what this Working group was looking at.

6 Impact Assessment, legal text, Implementation and National Grid viewpoint

Impact assessment, legal text and implementation

6.1 Following the Authority send back there would be no change to the original submission to the Authority for these sections of the Workgroup Report.

National Grid viewpoint

6.2 The main principle of Transmit was to better reflect the costs and benefits imposed by different types of generators on the electricity transmission network.

6.3 When assessing modification we feel it is necessary to look at the defect and exactly what it is seeking to change (i.e. is the scope narrow or large). In the case of CMP268 the defect is narrow. A number of key assumptions embedded in the baseline following Project Transmit and are not mentioned in the defect for CMP268, therefore for the purposes of this modification must be assumed to be correct and/or out of scope.

- Load Factor is an appropriate proxy to investment. Those Generators with greater outputs are more likely to trigger constraint therefore investment, and charging should reflect this
- 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
- In zones dominated by low carbon plant, those generators are less able to efficiently 'share' transmission network capacity because they tend to run simultaneously (e.g. when the wind is blowing). They are also expensive to constrain off compared to other forms of generation. Constraint costs will therefore tend to be higher in zones with high concentrations of low carbon plant. The non-shared element of Year Round tariff therefore increases as low carbon plant exceeds 50% in a zone and is not adjusted for ALF in recognition of this effect

6.4 As part of the analysis done as part of this modification, National Grid checked that the updated models still produced the same results, and they did. The underlying methodology and bid/offer prices remain very similar so the results matched expectation.

Basis of Not Sharing

6.5 The concept of Sharing was based on analysis which showed that there was a strong relationship between Load Factor and Constraint costs. However further analysis showed that this relationship broke down in certain zones in the future. It was found that the zones where the relationship broke down were dominated by Low Carbon Generation.

6.6 The concept of Shared and Not Shared was therefore introduced to better reflect investment costs.

Figure 1

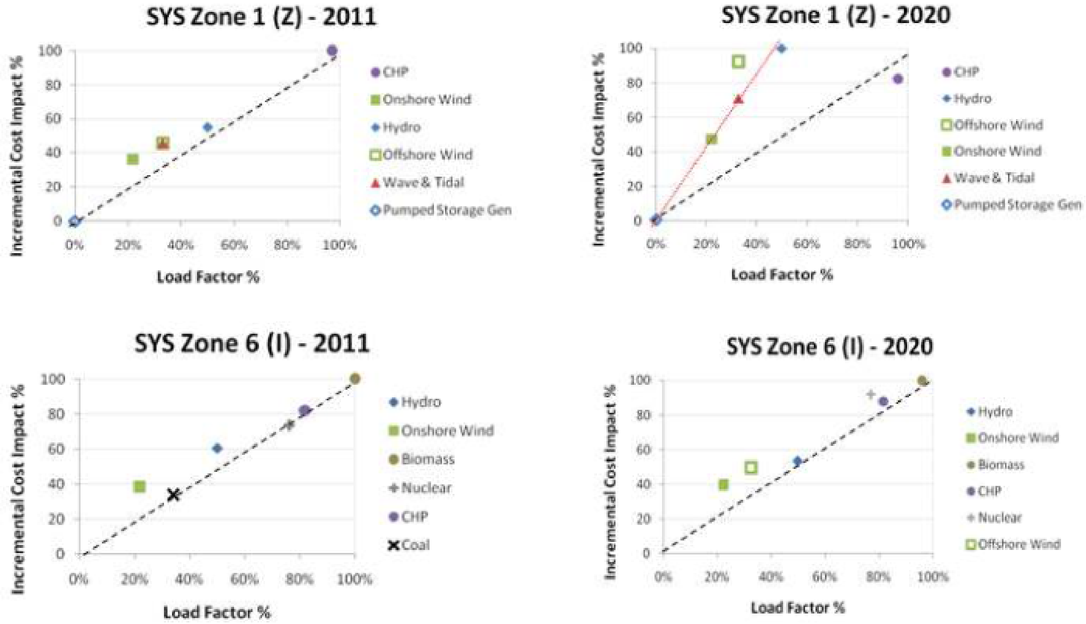


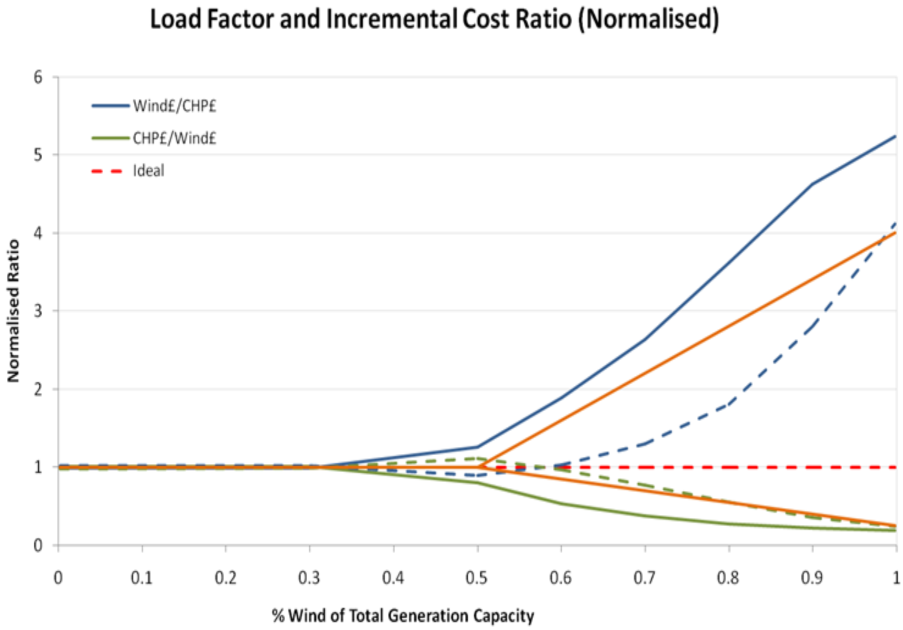
Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

Rationale for CMP268

6.7 Figure 2 below illustrates that the relationship between constraints and load factor deteriorates for Low Carbon generation (in terms of constraints increasing greater than Load Factor) when the proportion of this category of generation exceeds 50%. The relationship does not break down in the same way for Carbon Generation.
It is our view that there is sufficient evidence to show that treating Carbon and Low Carbon generation the same in areas of Low Diversity does not match the analysis and may be discriminatory in itself. It is our view that the implementation of this discrimination was not intentional and was simply a product of trying to manage the complexity of Transmit and the sheer amount of change.
Charging Low Carbon and Carbon differently in areas of Low Diversity is a natural extension to CMP213 and an incremental change.
To maintain a level of simplicity, we recognise that there are limited options in how to charge Low Carbon and Carbon differently. Carbon has a smaller impact than Low Carbon on constraints in areas of Low Diversity so any charge which reflects this, is better than the baseline.

When looking at the limited scope of the defect, reducing the Year Round Not Shared tariff for Conventional Carbon by Annual Load Factor results in tariffs being proportionally less for Conventional Carbon in areas if Low Diversity, so is therefore better than baseline.

Figure 2



Creating new Discrimination

6.8 We do not agree with the comments made that this modification is discriminatory as it does not address other areas of the current methodology where it is argued that the current methodology does not reflect investment costs. The scope of the defect of this modification is narrow to the point where it would be out of scope to address other perceived defects. To not address one defect because others exists would result in change only occurring if significant charging reviews were implemented which is inefficient.
However this comment does not preclude any future modifications to fine tune the current methodology.

Annex 1 – Additional details regarding Evidence & Analysis

This section includes additional details and background information regarding the new evidence and additional discussion of evidence which was summarised in section 2.

New evidence from National Grid National Grid Representative from CMP213 Workgroup regarding CMP213

A.1 The Workgroup discussed what further evidence could be provided and what evidence that had already been provided that could be considered further. It was concluded that the best approach would be to have a National Grid Representative from CMP213 Workgroup attend the Workgroup to facilitate a session on the CMP213 findings and Workgroup. This was carried out on the 20th February 2017. The main discussion points from this can be found below.

A.2 It was noted that TNUoS is used to do the following:

1. Collect revenue on behalf of transmission companies
2. Promote Effective Competition through
   - Transparency
   - Stability
   - Simplicity
   - Predictability
3. Reflect costs – long run, forward looking
4. Take account of developments in transmission business
5. Be Non-discriminatory

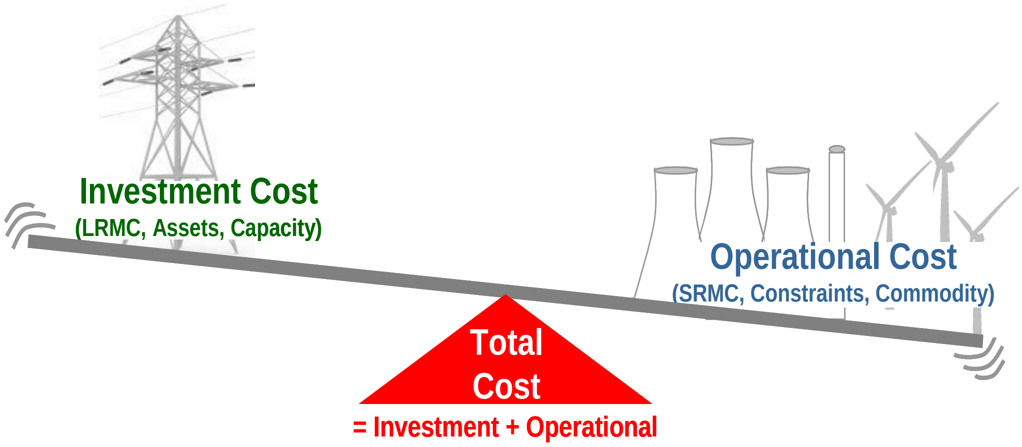
Whilst all of these things need to be done the challenge for the Charging Methodology is to balance number two and three. The key challenge is the **balancing of simplicity with cost reflectivity?**

The CMP268 Workgroup then looked into how the CMP213 Workgroup had assessed options to amend the Methodology.

A.3 <u>**Background to principles of sharing network capacity**</u>

A.3.1 The CMP213 Workgroup assessed whether there was there a way that the Methodology could be adapted to include where plant 'Share' capacity and if so how could this work. The graph below illustrates an example of how this works in practice.

A3.2 When the CMP213 Workgroup assessed how the methodology could charge for the Sharing component they looked at the following:

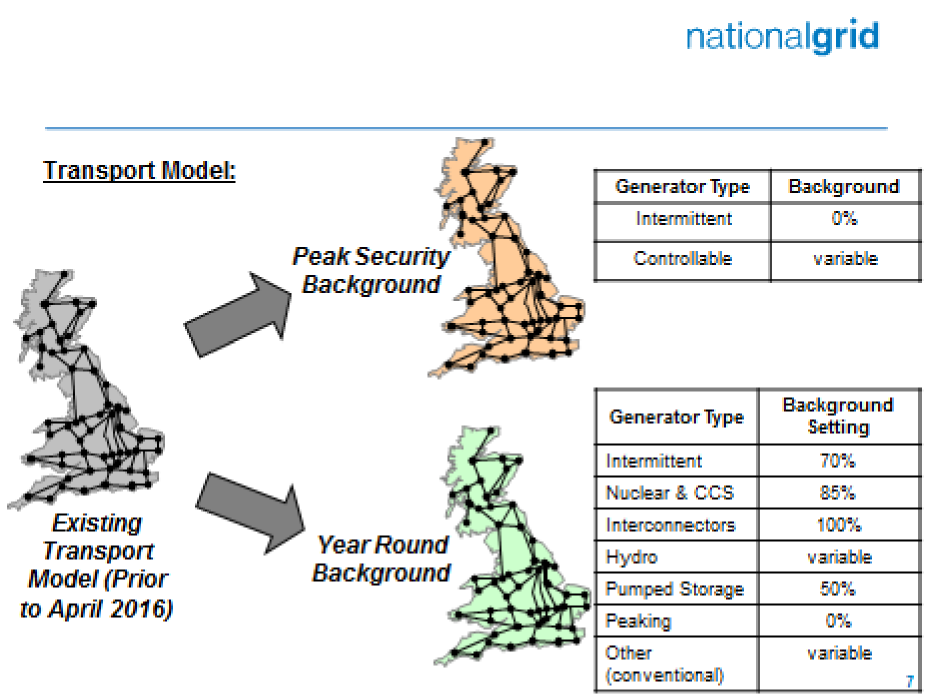


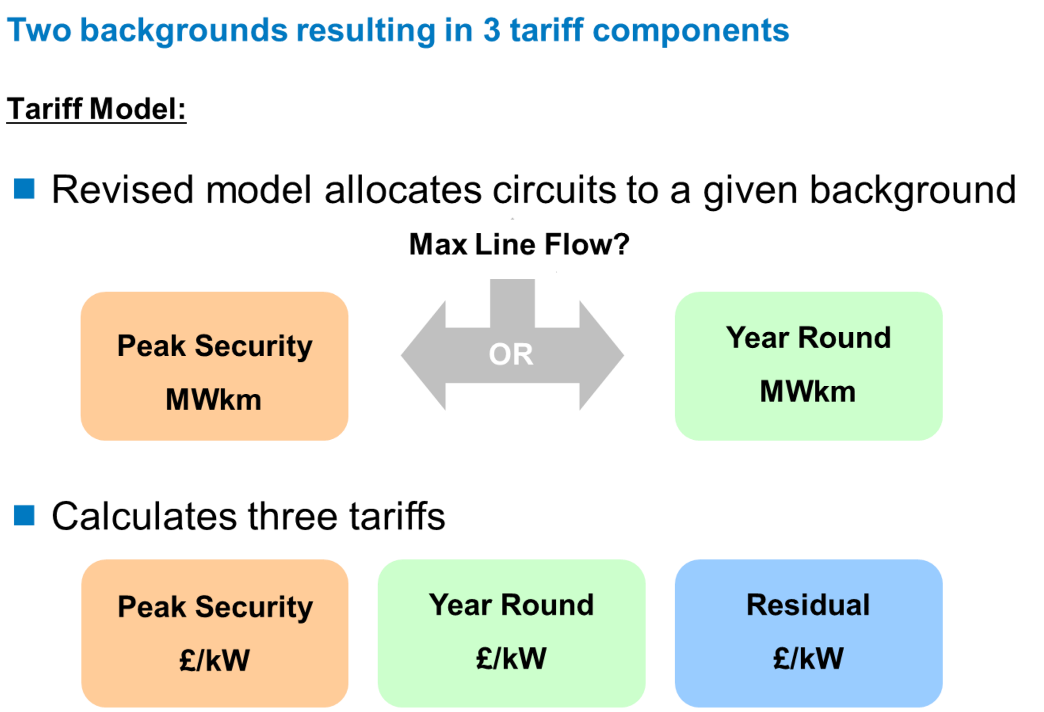
- Network capacity vs. future savings in operational costs
- Some investment remains demand security driven
- Charging methodology should develop to reflect the above points
- Must remain simple, transparent and non-discriminatory
- Use long term convergence of LRMC and SRMC

A3.3 It was noted that implicit assumptions must be made as explicit information was not available and that for investment driven by “year round” conditions, these should reflect assumptions made in cost benefit analysis carried out by the TSO when making investment plans. It was also noted that TSOs are incentivised to balance SRMC and LRMC.

Transport Model – Methodology today (baseline)

A.4 The Methodology that was approved by the Authority and implemented in April 2016 is based on the Model developed during the Transmit process that shown below;





This section (Annex1) outlines some workgroup member's views on the presentation given by the National Grid representative. The views of other Workgroup members can be found in the Cost reflectivity paper at Annex 4

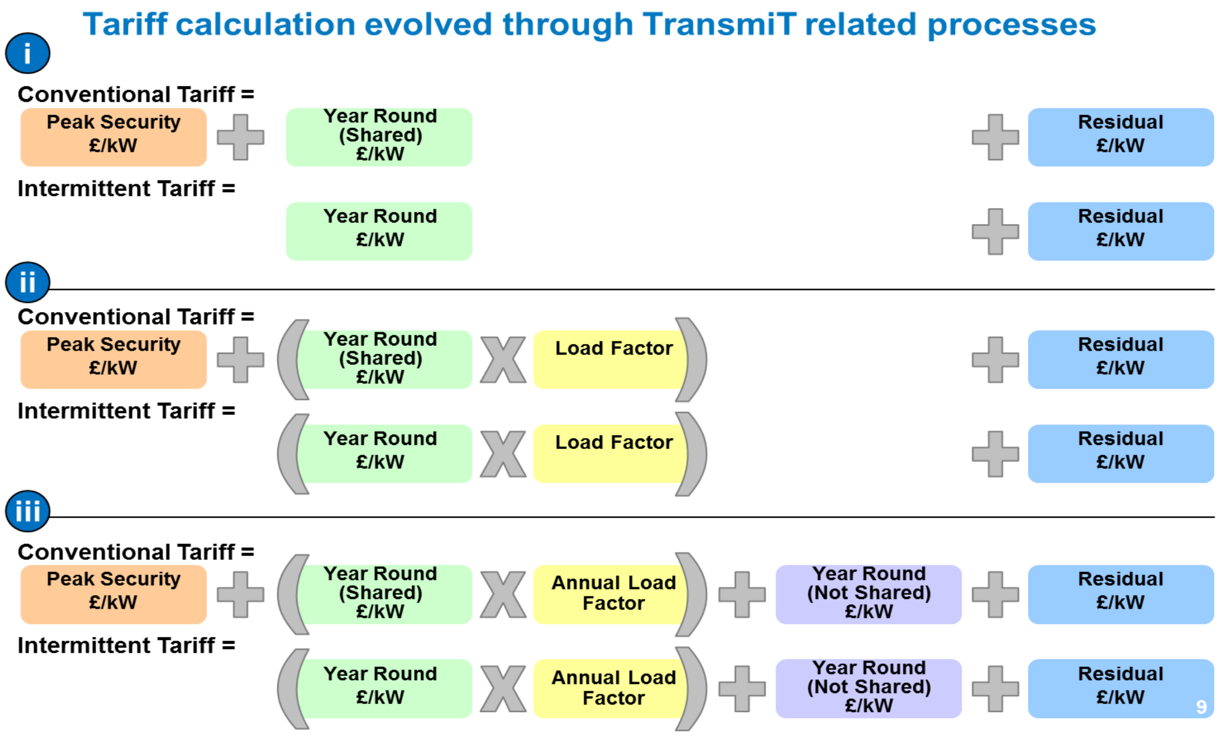
A.5 The National Grid Representative from CMP213 Workgroup then talked through the fact that this meant that the Methodology that was approved by the Authority has four tariff components as set out below (more information on how the circuits are allocated to either Peak or Year Round can be found within Annex 2 and is what we now know as the Baseline Methodology today.

A.6 The solution which was ultimately approved by the Authority underwent several stages of development and incremental revision prior to being presented to the Authority as described in the graphic below. Each stage of revision involved the balancing of achieving incrementally improved cost reflectivity as compared with adding additional complexity to the methodology. Three stages of this process are illustrated in the diagram below as:

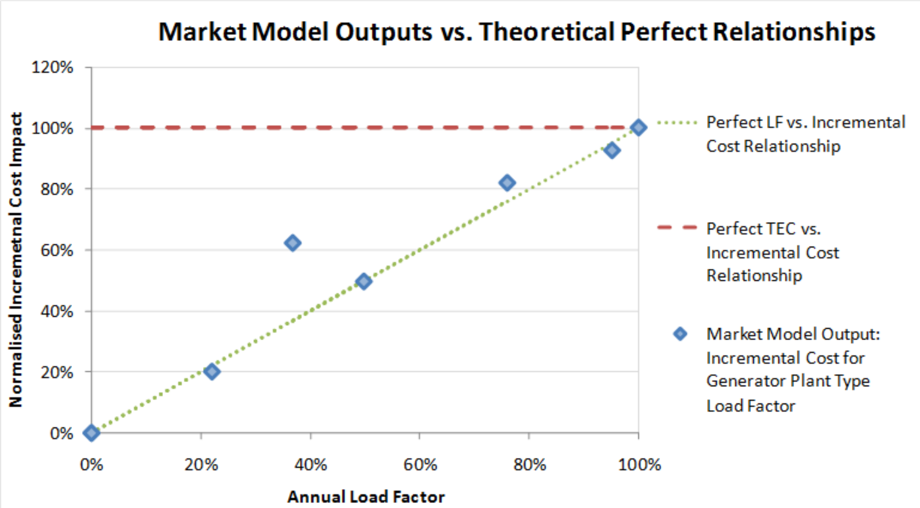
Creation of a dual background Transport model leading to a potential solution which used three tariff elements: Peak Security, Year Round and Residual.

The CMP213 Original proposal included an additional element to improve the cost reflectivity of the methodology whereby the Year Round tariff element would be multiplied by ALF.

During the CMP213 Workgroup process, a range of alternatives methodologies for dealing with diversity were developed including Diversity 1, which became WACM2 which the Authority ultimately approved. The incremental change added by WACM2 resulted in four tariff elements. This solution aimed to improve the cost reflectivity of the solution by taking account of circumstances where the System Operator is more likely to take bids from more expensive bid price Low Carbon plant which is more likely to occur in areas with a higher concentration of Low Carbon generation. This change introduced to reflect this was achieved by taking the additional step of dividing the Year Round tariff into two parts: Year Round Shared which was still adjusted by ALF and Year Round Not Shared which was applied at 100% of TEC.

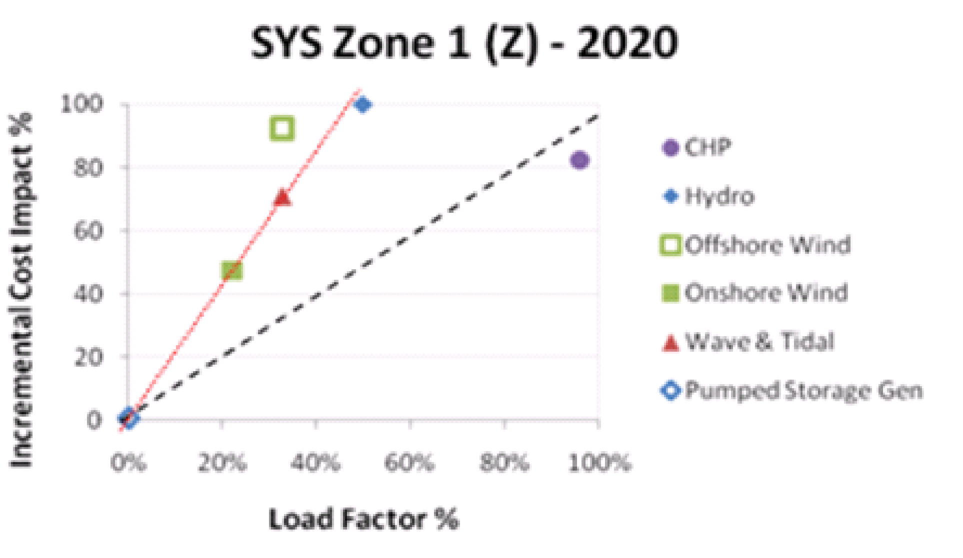


A.7 The National Grid Representative from CMP213 Workgroup talked through the relationship between the ALF and incremental costs. It was noted that the relationship was not a perfect one and that in areas dominated by Low Carbon, the relationship diverges due to the more expensive bid prices of low carbon plant. The diagram below illustrates why ALF was used in the Charging Methodology. It was thought to be simple and the CMP213 Workgroup thought it to be more cost reflective than using TEC because the relationship between ALF and normalised incremental cost impact is clearly stronger than with TEC and normalised incremental cost.



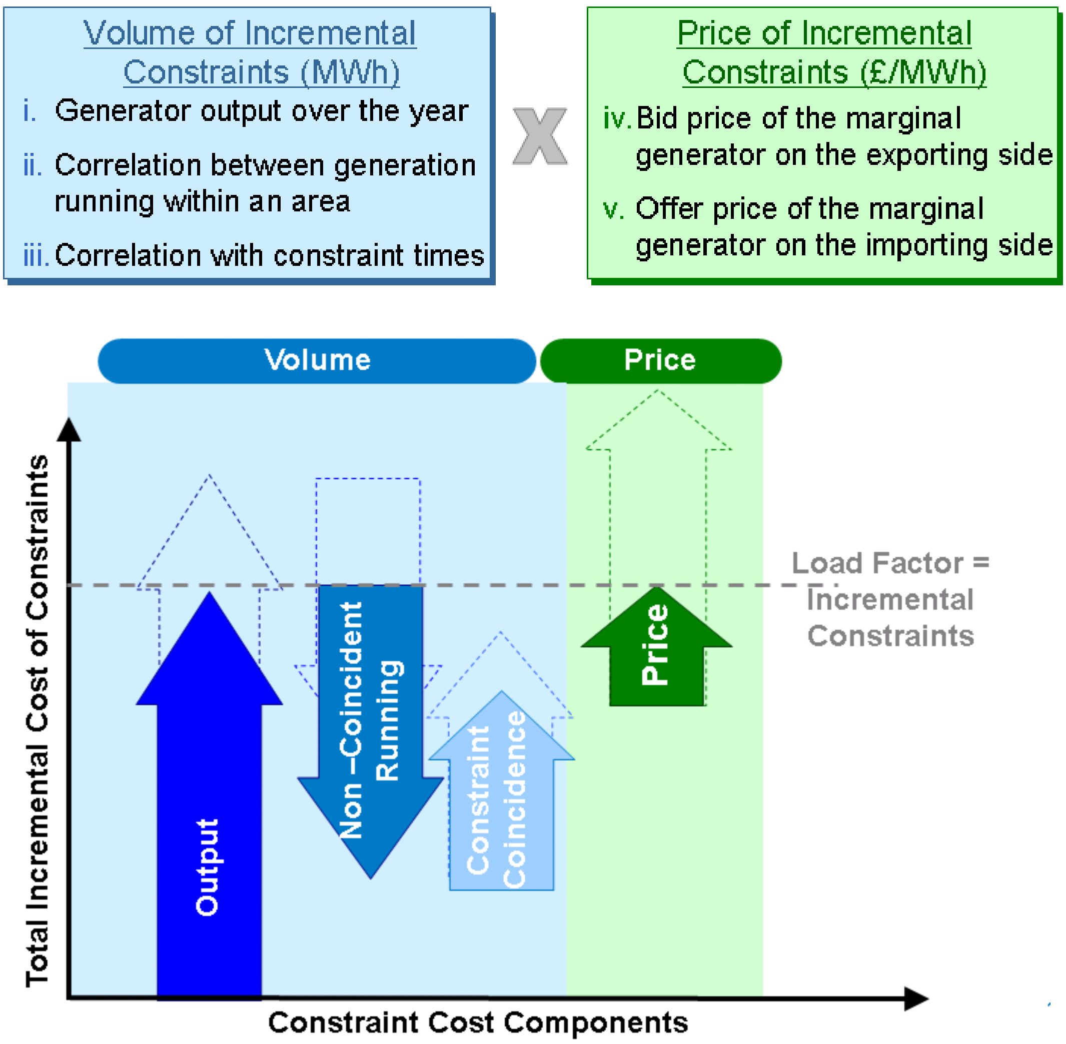
ELSI Full Market Modelling results

A.8 (Slide 14) A workgroup member asked the National Grid Representative from CMP213 Workgroup if it was correct to interpret on the presented graph (SYS Zone 1 (Z) – 2020 graph below), that it is only those generators classed as “Low Carbon” which are shown above the idealised 45 degree full sharing line, while those generators classed as “Conventional Carbon” are shown to remain either on or below the line. The National Grid Representative from CMP213 Workgroup confirmed that it was correct to interpret the graph in that way. The proposer noted to the workgroup that the interpretation was consistent with his rationale for CMP268 which had already been discussed within the workgroup and noted within CMP268 Final Modification Report]. A workgroup member also agreed with this interpretation

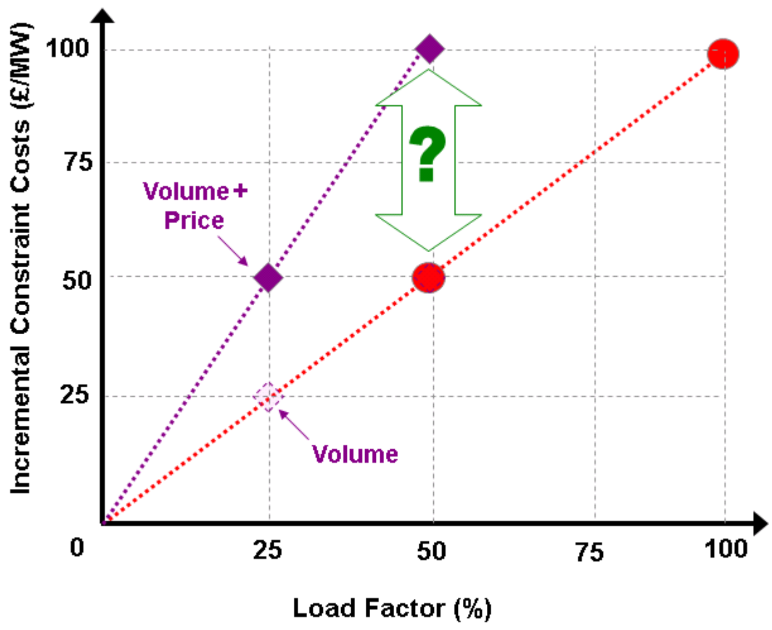


A.9 **Important lessons can be learned from considering the principles behind the economics of sharing**
(Slide 15-20) The National Grid Representative from CMP213 Workgroup explained that this picture shows the economic principles which drive the degree of sharing and how each element contributes

to the incremental cost of constraints (including output, correlation and bid price).



A.10 (Slide 20) The National Grid Representative from CMP213 Workgroup stated "Low cost bid plant stays on the line. Only high cost bid plant [Low Carbon] moves above the line" [i.e. as diversity reduces, it is <u>only</u> the expensive bid price plant (Low Carbon) which causes an increasing incremental constraint cost, while by contrast, the incremental constraint cost for low bid price plant (Conventional Carbon) remains proportional to ALF].



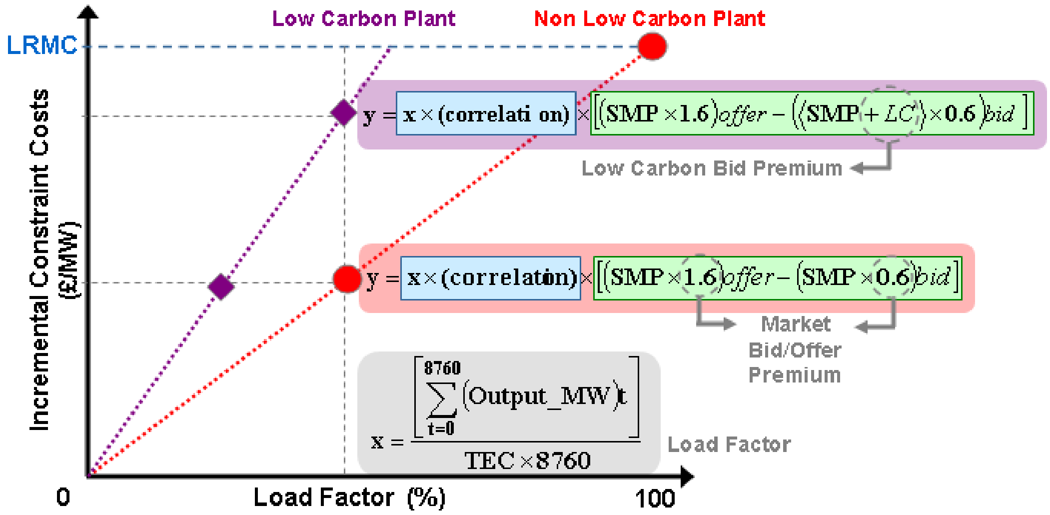
A.11 Slide 75-87 provided further analysis of this relationship using ELSI model. This is most clearly summarised in slide 87, below, noting this graph is already included in CMP268 FMR along with explanation which was consistent with the National Grid Representative from CMP213 Workgroup's presentation.

A.12 The National Grid Representative from CMP213 Workgroup explained that (assuming volume remains unchanged), if an area has low diversity, then the divergence in cost caused occurs because Low Carbon Plant cause an additional incremental cost due to their more expensive bid prices reflected by the "Low Carbon Bid Premium",, while the factors which drive incremental cost caused by Non Low Carbon plant remains unchanged (i.e. the same as it is in a high diversity area).

A.13 For Conventional Carbon plant this result is achieved because as shown in this illustration, the volume at times of constraint remains the same and the price of constraint remains the same, so the overall incremental cost of constraint which it causes also remains the same, so it continues to be appropriate to apply the ALF to the whole Year Round tariff (including both Shared and Not Shared elements).

A.14 Furthermore, this analysis also demonstrates that if there is was reduction in the correlation between Conventional Carbon generators and periods of constraint, then for a given ALF, there would be a reduction in the volume of constraints element, therefore the incremental constraint cost which Conventional Carbon generators cause could reduce below the red dotted line and would therefore reduce to be lower than their ALF.

A.15 The National Grid Representative from CMP213 Workgroup presented the following graph, which illustrates this relationship in more detail. The CMP268 FMR also included this same graphic with a consistent explanation.



A.16 The CMP213 FMR included this same graphic and provided a consistent explanation of this relationship as per the paragraphs below:

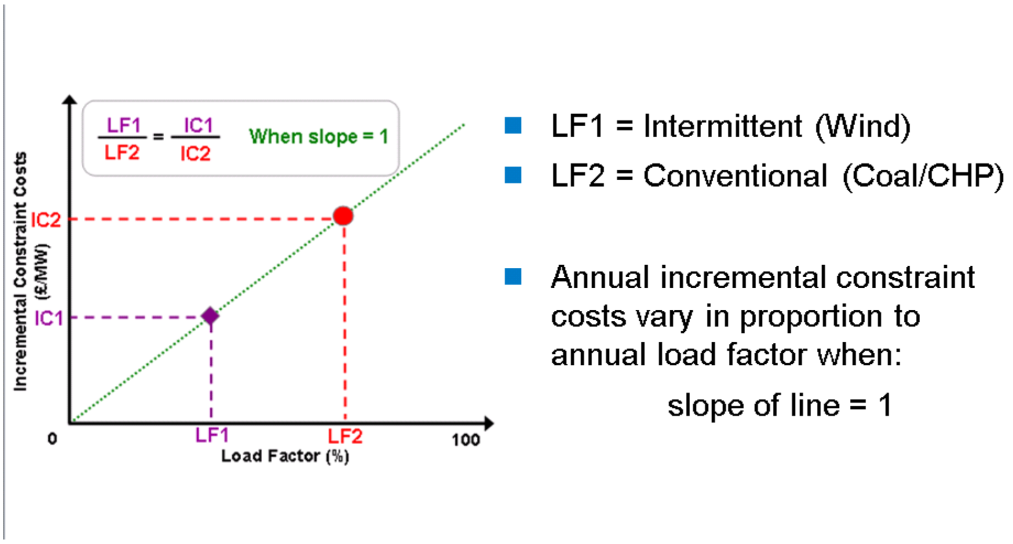
"*From the above [graph shown above] the [CMP213] Workgroup appreciated that, for areas of the transmission system with sufficient generation plant diversity and a correlation of running and constraints fixed at that of the optimally invested transmission network level (i.e. at the point where incremental 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 [CMP213] Proposer in the ELSI market model used to produce the generation annual load factor vs. incremental constraint cost graphs shared with the Workgroup.*

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]*

Effects of diversity tested in Market Model (Slide 21-26)

A.17 The National Grid Representative from CMP213 Workgroup explained the implications of this analysis with regard to the relative incremental cost of different types of generator.

A.18 Slide 23 of the National Grid Representative from CMP213 Workgroup's presentation, shown below, illustrated the expected normalised relationship where "Annual incremental constraint costs vary in proportion to annual load factor when: slope of line = 1"

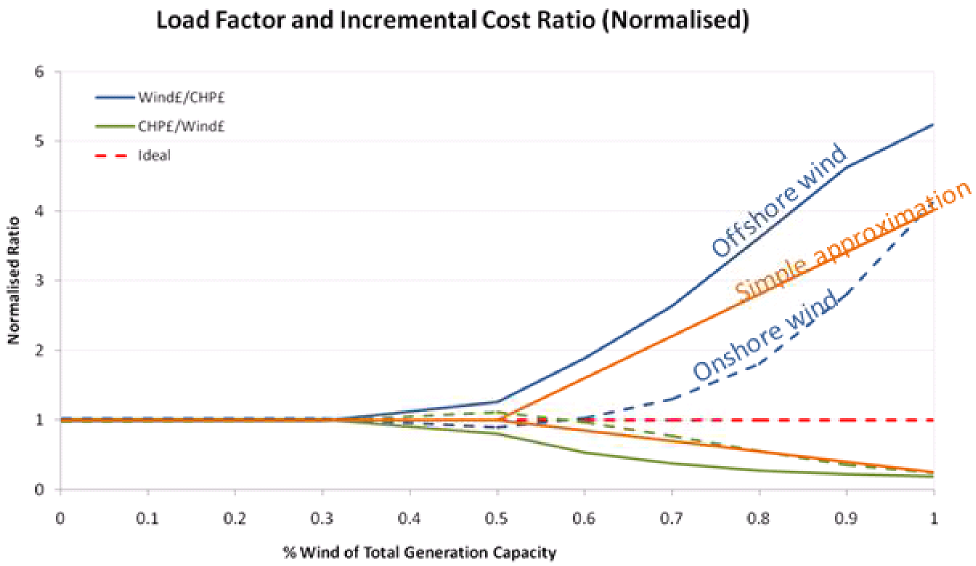


A.19 Slide 98 of the National Grid Representative from CMP213 Workgroup's presentation, shown below, illustrated the key analysis carried out during CMP213 which informed the 50% trigger point for breakdown in sharing. This showed that beyond 50% concentration of low carbon generation, the normalised ratio deteriorated such that the normalised incremental cost caused by wind (Low Carbon) increased from 1 to circa 4 to 5 times that of CHP (Conventional Carbon). I.e. as the diversity reduces the difference increases between the cost caused by the two broad categories of generation (expensive bid price vs low cost bid price). Therefore as diversity reduces, the incremental cost caused by expensive bid price plant(Low Carbon) becomes progressively relatively more expensive than low cost bid price plant (Conventional Carbon).

A.20 The graph below from CMP213 evidence summarises the results of this analysis showing plant classed as Low Carbon represented by onshore and offshore wind, compared with plant classed as Carbon which is represented by CHP. This analysis was also repeated for other types of Carbon plant in different market scenarios with consistent results. The normalised ratio relates to the ratio of the incremental constraint cost caused y wind divided by the incremental constraint cost caused by CHP, normalised for the difference in their load factors. This graph below illustrates that in this analysis, if the incremental cost caused by all types of plant remains proportional to their ALF, then the normalised ratio between those different types of plant of their respective incremental cost resulting from the ELSI model would be at, or close to the idealised ratio for full sharing represented by "1" as shown by the horizontal red dotted line on the graph below. As the graph shows, the ELSI modelling results did show this was the case as long as the penetration of wind remained less than 50%. From considering the results of this analysis, the

CMP213 workgroup reached the conclusion that in circumstances of less than 50% concentration of Low Carbon generation, it is appropriate and cost reflective to charge the Year Round tariff to all types of generator based on their ALF.

A.21 The proposer noted that CMP268 is consistent with this result, however, Baseline runs contrary to this evidence because Baseline treats expensive bid plant and low cost bid plant as if they are the same as each other in this regard.



A.22 **The National Grid Representative from CMP213 Workgroup stated that he could not see any benefit in replicating the CMP213 analysis for this Workgroup (CMP268) because it would just give the same answer because the principles have not changed.**

Bid prices (Subject matter export Slides 55-74) Bid price is shown to be the key to the classification between “Carbon” and “Low Carbon”

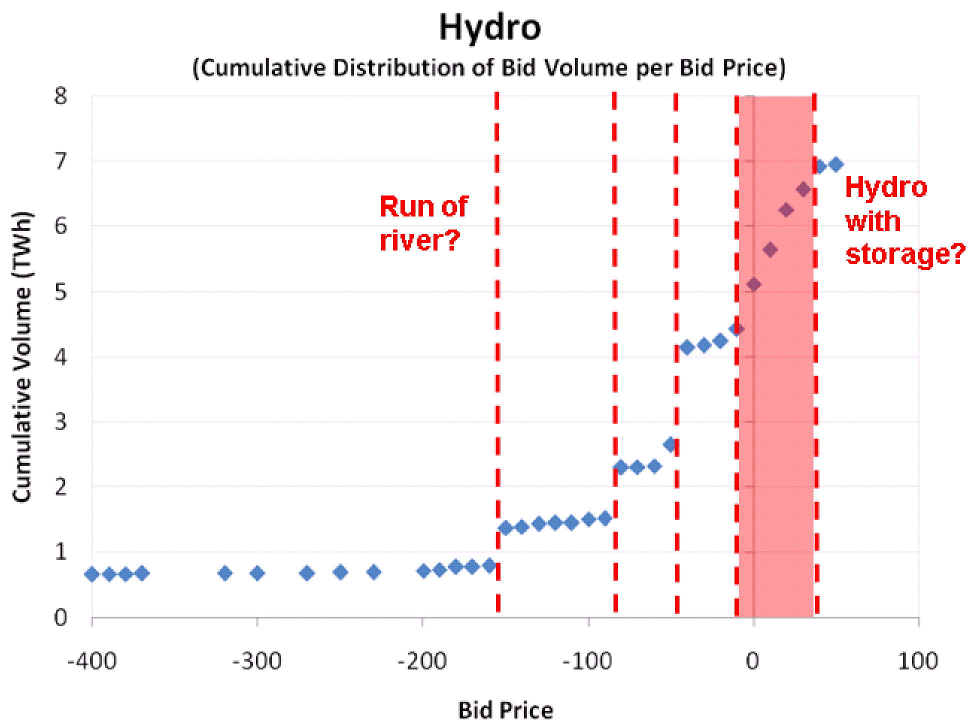
A.23 The CMP268 Workgroup concurred with observation that the CMP213 Workgroup had agreed that the classification “Carbon” vs “Low Carbon” is simply a naming convention used to mean “expensive bid price” vs “low cost bid price”

A.24 The table in National Grid Representative from CMP213 Workgroup slide 57, shown below, shows different bid price points to the right hand side of the table. This shows that those stations currently classed as “Conventional Carbon” tend to exhibit relatively low cost bid prices (Coal, Gas, OCGT, Oil), while those stations currently classed as “Low Carbon” tend to demonstrate relatively expensive bid prices (Hydro, nuclear, wind).

Fuel Type	Price Point 1 (£/MWh)	Price Point 2 (£/MWh)	Price Point 3 (£/MWh)
Coal	-1,000	-90	0 to 30
Gas	-10,000 to -4,000	-180	0 to 40
OCGT	-100	30 to 50	320
Oil	0	40	-
Hydro	-150	-90 to -50	-10 to 40
Nuclear	-10,000	-	-
Wind	-10,000	-175	-150

A.25 The National Grid Representative from CMP213 Workgroup stated that this explains the reason as to why the result was obtained that beyond 50% concentration of Low Carbon generation, it is only expensive bid price Low Carbon plant which moves above the idealised sharing line, while inexpensive bid price Carbon plant does not move above the idealised line. The explanation was given that when a plant is constrained off, the cost to the SO is the price spread between the plant bid off and the corresponding plant offered on to fill the gap. Most plant offered on will be gas or other conventional carbon. The price spread between gas and gas is narrow, so gas, or other Conventional Carbon, will always tend to provide a relatively low incremental cost way of managing constraints. By contrast, the price spread between wind, or other Low Carbon plant and gas is large, which explains why wind, or other Low Carbon plant does cause a relatively high incremental cost of managing constraints.

A.26 Slide 67 of the National Grid Representative from CMP213 Workgroup's presentation, shown below, showed that the CMP213 workgroup identified that there may be benefit in further considering the sub classification of hydro into "Run of River" compared with "Hydro with storage" based on differences in cost of bid prices. This issue was not investigated any further by the CMP213 workgroup at the time.



<u>**Discussion of analysis from CMP213National Grid Representative from CMP213 Workgroup**</u>

The Workgroup agreed that a useful new insight for CMP268 could be obtained from considering the National Grid Representative from CMP213 Workgroup's slides 89-100

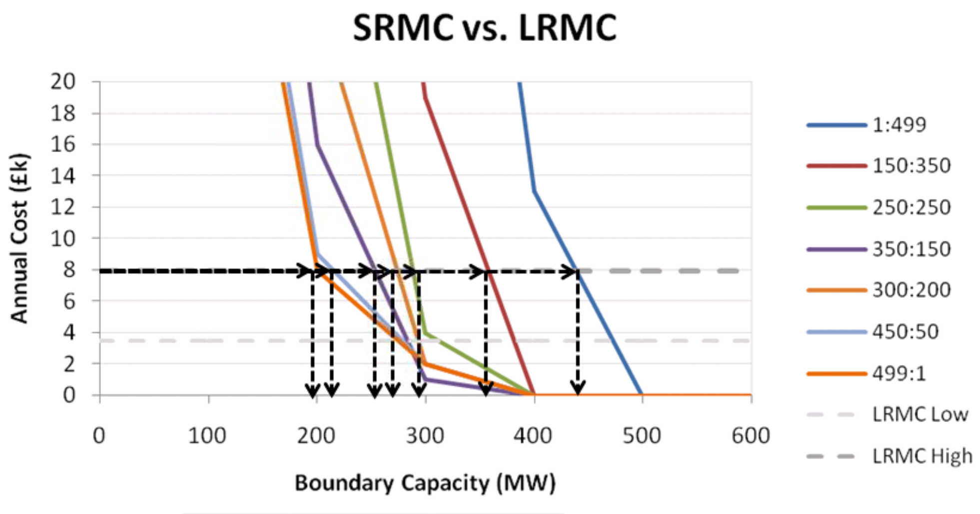
A.27 National Grid Representative from CMP213 Workgroup's slides 89-100 show more detail of the working behind slides 21-26. The Workgroup agreed it would be useful to re-visit the information in these slides. The analysis represented by these slides was discussed in detail in a subsequent CMP268 Workgroup meeting which is summarised in the following section.

Additional discussion of the new CMP213 evidence regarding incremental costs

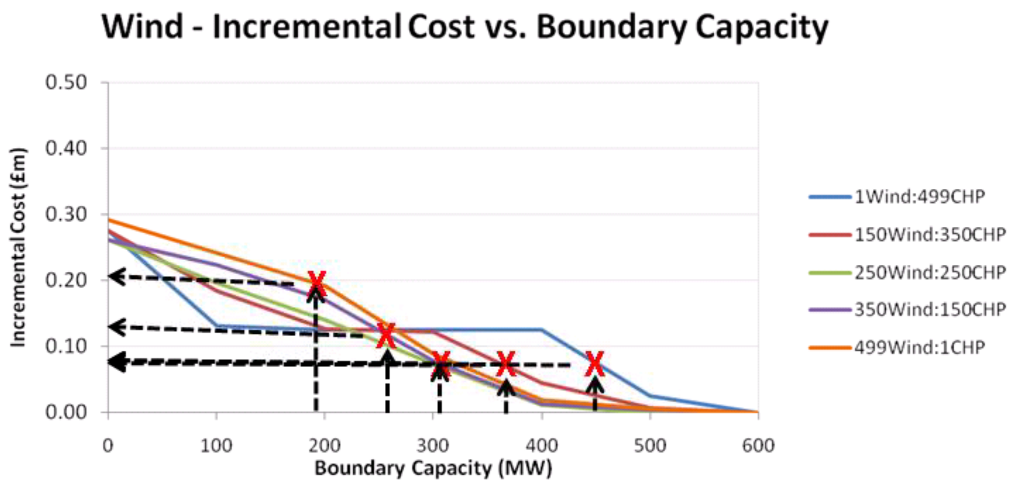
A.28 Following the National Grid CMP213 National Grid Representative from CMP213 Workgroup presentation, the Workgroup noted that it would be useful to subsequently consider in greater detail the evidence which the National Grid Representative from CMP213 Workgroup provided with regard to the relative incremental cost of different types of plant. In order to deliver this action, the proposer presented to the Workgroup annotated versions of a selection of the National Grid Representative from CMP213 Workgroup's slides which the Workgroup then discussed in greater detail. A selection of illustrations from this presentation and a summary of the Workgroup discussion is provided below.

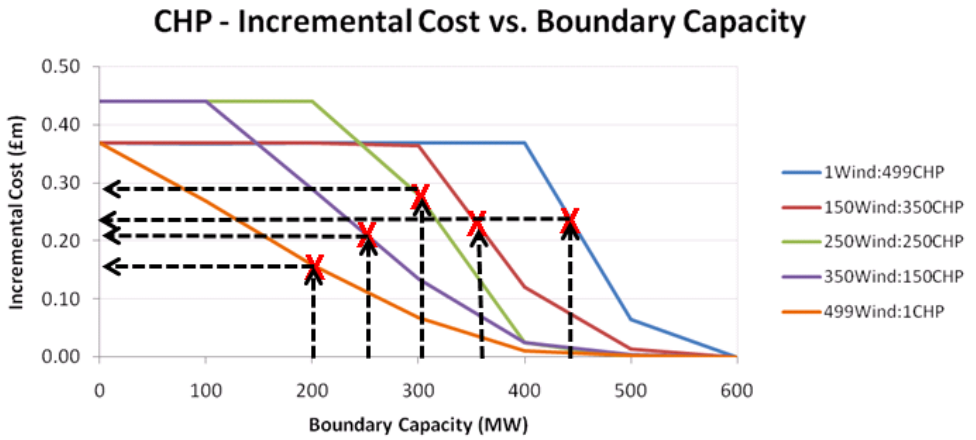
A.29 The Proposer explained that the specific part of the evidence which was discussed in greater detail explained some of the analytical steps which National Grid carried out during the CMP213 Workgroup process to understand how the incremental cost caused by different types of generator changes when an area becomes increasingly dominated by Low Carbon generation. The graphs below step through the different stages of this starting by considering a range of different plant mix scenarios, identifying the optimum network boundary capacity for each plant mix scenario, then calculating the different incremental constraint cost caused by an incremental 1MW of each generation type using National Grid's ELSI modelling tool.

A.30 The Proposer explained that the first step by National Grid required identifying the optimum boundary capacity for each plant mix. This is illustrated on the annotated graph below where for a given portfolio mix of generation, the optimum boundary capacity is determined by the intersection between the LRMC shown by the horizontal grey dotted line and the SRMC for the relevant plant mix scenario as shown by each coloured line on the graph. The optimal boundary capacity for each plant mix scenario can then be read from the x axis of the graph as per the annotated black dotted arrows.



A.31 The proposer explained that the second stage of the National Grid analysis was to calculate the different incremental cost caused by different types of generator for the given plant mix scenario and given optimum boundary capacity as shown by the annotated black dotted arrows on the graph below. This was achieved by reading the the optimum boundary capacity for each plant mix scenario on the x axis (the value of which was calculated from the graph above), then where this intersects with the relevant incremental cost curve for the relevant plant mix scenario, reading across to the associated incremental cost on the y axis. The graphs below illustrate this for two differnet classes of generator: Wind (Low Carbon) and CHP (Conventional Carbon).

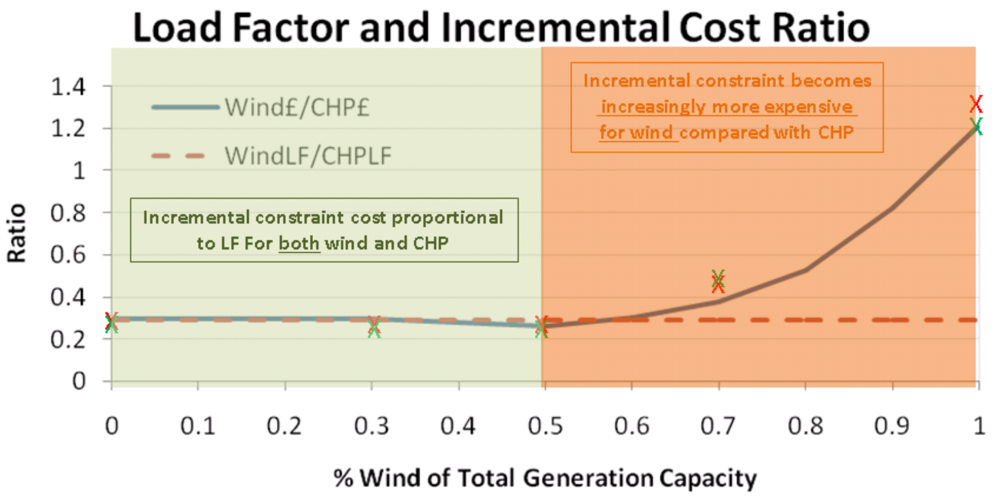




A.32 The proposer noted that the data points for incremental cost of each plant type (represented by red crosses) can be read from right to left showing how the incremental cost of each technology changes as diversity reduces and the generation mix becomes progressively dominated by wind. This clearly shows that firstly, as the concentration of wind <u>increases (reading the red crosses from the right towards the left side of the graph)</u>, then the incremental cost caused by wind also increases. Secondly, by contrast the effect on CHP is the reverse of this relationship as the graph clearly shows the incremental cost caused by CHP tends to <u>reduce</u> when the concentration of wind increases (reading the red crosses from the right hand side towards the left hand side of the graph). These two opposite responses explain why as the level of diversity reduces, because the incremental cost caused by Carbon and Low carbon plant diverge from each other because the cost of Low Carbon increases while the cost of Carbon decreases.

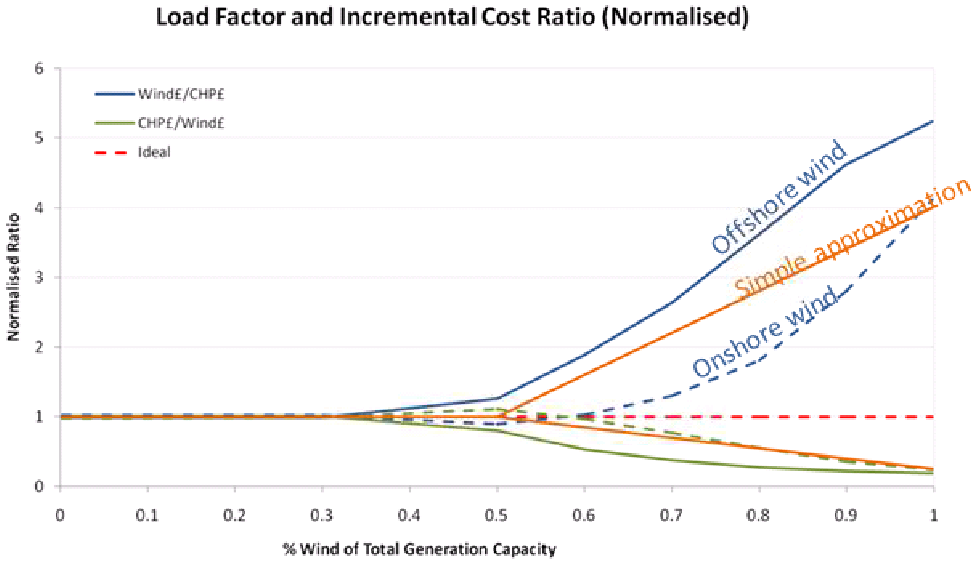
A.33 The third stage of the National Grid analysis was to calculate the ratio of incremental constraint cost by taking the incremental constraint cost caused by wind divided by the incremental constraint cost caused by the CHP. The result of this calculation is shown on the graph below

A.34 The Proposer presented that the graph below shows that when the degree of diversity is high (% of wind of total generation of total generation capacity is less than 50%), then the ratio between the two is the same as the ratio of their load factors i.e. wind LF 22% divided by CMP LF 75% = ratio of 0.29. This result is consistent with the CMP213 approach of applying the ALF to the Year Round Shared tariff for all types of generator. Further, the graph also shows the divergence in incremental cost between carbon and low carbon generators when the % wind of total generation capacity exceeds 50%. As explained above, this divergence occurs because beyond 50% wind concentration, the incremental cost of constraints caused by the wind (Low Carbon) increases, while the incremental cost caused by the CHP (Conventional Carbon) decreases.



A.35 The annotation of data points reflecting ratios on the graph above marked by "crosses" were calculated by the proposer reading off the graphs, which introduces a small element of error, which explains why they differ slightly from the original curve calculated by the National Grid National Grid Representative from CMP213 Workgroup .

A.36 The proposer explained that the original CMP213 analysis carried out the same analytical approach for a range of different generation technologies and scenarios to derive the following "normalised" ratio graph. This shows that for two generators with the same load factor, they would be expected to cause the same incremental cost as long as there is sufficient diversity. However, beyond 50% concentration of wind, the cost of different generators diverges as Carbon plant cause a lower cost compared to that caused by Low Carbon plant.



Proposers further comments on CMP268 and generators in negative "not shared" zones

A.37 The workgroup identified that there are two generation charging zones which currently exhibit a negative YRNS tariff which are zone 22 and 23. Within these zones, there are only two stations, both of which are classed as Conventional Carbon. These two stations are Taylors Lane, which is an OCGT peaking plant with an ALF of 0% located in zone 23 and Seabank, which is a CCGT with an ALF of 24% located in zone 22. There is no generation classed as Low Carbon in either of these zones.

A.38 The Workgroup discussed the impact of CMP268 on the charges paid by generators in zones which have a negative Year Round Not Shared tariff and concluded that the effect of CMP268. All workgroup members agreed that the new proposed methodology has a material impact on these stations as it removes the negative Year Round Shared tariff. For Taylors Lane this will increase the liability by £1m.

A.39 Some workgroup members agreed with the materiality of the change but argued that although the change it material it is justified due to the following reasons.

- A negative Year Round Not Shared tariff is a product of how the methodology is applied to Parallel zones (please see annex 2) resulting in a signal which does not reflect an investment signal but reflects the difference in MWkm of Parallel zones.

- Therefore is it not right for a negative Year Round Not Shared tariff to exist at all. Removing this benefit is an unintended consequence of CMP268 but arguably the end result is better than the baseline

A.40 Some workgroup members concluded that the because these zones are in fact fully shared, this means there is no economic justification for the Baseline to treat any proportion of the Year Round tariff for these zones as if it were not shared. Therefore where the Baseline gives a reward based on 100% of TEC on a YRNS tariff even though the network capacity for that zones is fully shared means that Baseline confers a benefit to certain generators which is too high and is therefore not cost reflective.

A.41 Some workgroup members believe that CMP268, by introducing ALF to the YRNS, reduces the potential scale of this non-cost-reflective outcome of the Baseline. At one end of the ALF spectrum (100% load factor) CMP268 makes no difference to the incentive offered by the YRNS in these zones in the hypothetical situation where a generator has an ALF of 100%. At the other end of the spectrum, for a plant with an ALF of zero, the incentive reduces to zero (the theoretically correct level). Thus CMP268 cannot make the situation worse than baseline and rather it can only be better than baseline in this regard.

A.42 Some workgroup members stated that there is no contingent issue for CMP268 regarding whether this issue may, or may not be addressed at some point in the future. This is because CMP268, for Conventional Carbon generators, does treat all Year Round tariffs elements the same as each other i.e. the ALF is applied to the Year Round “shared” tariff element in exactly the same way as ALF is applied to the Year Round “not shared” tariff element. Therefore CMP268 would result in exactly the same locational tariffs for Conventional Carbon plant in zones 22 and 23 irrespective of whether this parallel zone feature may remain the same as Baseline (as described above), or whether it may be changed in the future.

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New modelling analysis provided by National Grid Economics Team

Introduction

A.43 The Economics Team at National Grid requested to perform a comparison of constraint costs between a wind connection and a CCGT connection. To perform this, a 500MW onshore wind site and 500MW CCGT were added to an existing network model of the UK into the North of Scotland, specifically in Zone Y (between wider network boundary B1 and B2). An economic dispatch was then performed on an unconstrained and then constrained network to produce a forecast of the Total Balancing Mechanism costs for each case. This was performed on the FES2016 Gone Green and No

Progression backgrounds in order to provide a breadth of scenario, and was modelled for calendar years 2018 and 2019.

Results

A.44 The below table and chart shows the difference in constraint costs across the scenarios. In all cases the wind and CCGT increase constraints when compared to the base case as there is assumed to be no further boundary reinforcement for the additional 500MW of generation. It can be seen that the wind generation produces higher constraint costs when compared to that of the CCGT in all cases. As the connections are in Scotland, which is considered a constrained area of the network until reinforcement can be delivered; there is naturally a higher level of constraint for increased generation. The constraints are calculated from "bid" and "offer" prices whereby a constrained plant would be bid-off to alleviate a constraint, and plant in an unconstrained area would be offered-on. For wind, the bid prices are proportional to the Renewable Obligations Certificate rates to reflect a level of compensation that the generator may seek in the balancing market from potential losses in revenue. For CCGT, the bid and offer prices are derived from historic economic data from previous bid and offer behaviour.

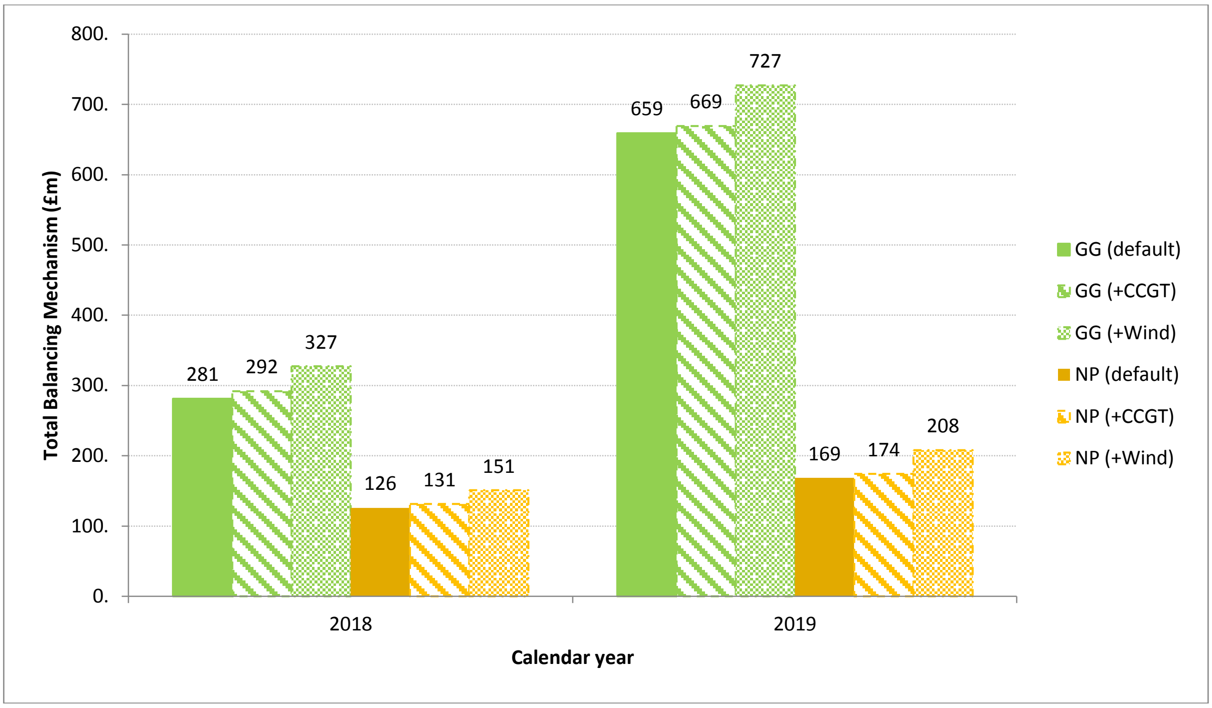
A.45 Ultimately a CCGT may pay the System Operator not to operate at a level lower than their Short Run Marginal Cost (SRMC) as they have an opportunity to save money or perhaps even make money (e.g. trading their fuel gas), whereas a wind farm has a SRMC of virtually zero and so would not benefit from being bid off and would only serve to lose from lost generation revenue. The lower SRMC and renewable obligations places wind far lower in the merit order and so would be dispatched ahead of a CCGT.

A.46 The constraint costs incurred by the connection of a 500MW CCGT are on average between the scenarios 14% lower than an equivalent connection of a 500MW onshore wind farm relative to the overall system constraint costs (£27m lower for 2018 and £46m lower for 2019)

Table 1 – Differences in national constraints due to differences in generation type

Scenario	**Difference in constraints compared to base scenario**			
	2018		**2019**	
	Wind	**CCGT**	**Wind**	**CCGT**
Gone Green	16.3%	3.7%	10.3%	1.5%
No Progression	19.7%	4.2%	23.4%	3.3%
Average	18.0%	4.0%	16.9%	2.4%
= Wind - CCGT	14%		14%	

Figure 1 – Forecast Total Balancing Mechanism for each scenario



A.47 The proposer observed that the new analysis which carried out by National Grid (presented in section 4 of this report) illustrates this same relationship as the original CMP213 analysis described above. Using this new National Grid modelling, this showed that the constraint cost caused by wind was between 4x and 7x greater than that of the CCGT, as illustrated in the tables below. The first table is simply shows the results as quoted by National Grid, while the second table shows an additional piece of analysis carried out by the proposer using the same National Grid results to calculate the ratio of the constraint cost caused by the incremental wind divided by the constraint cost caused by the incremental CCGT.

Scenario	Ratio of constraint cost Wind : CCGT	
	2018	2019
	Wind : CCGT	Wind : CCGT
Gone Green	4.4x	6.9x
No Progression	4.7x	7.1x
Average	4.5x	7.0x

Additional discussion of NERA/ICL evidence – further explanation from the Proposer of CMP268

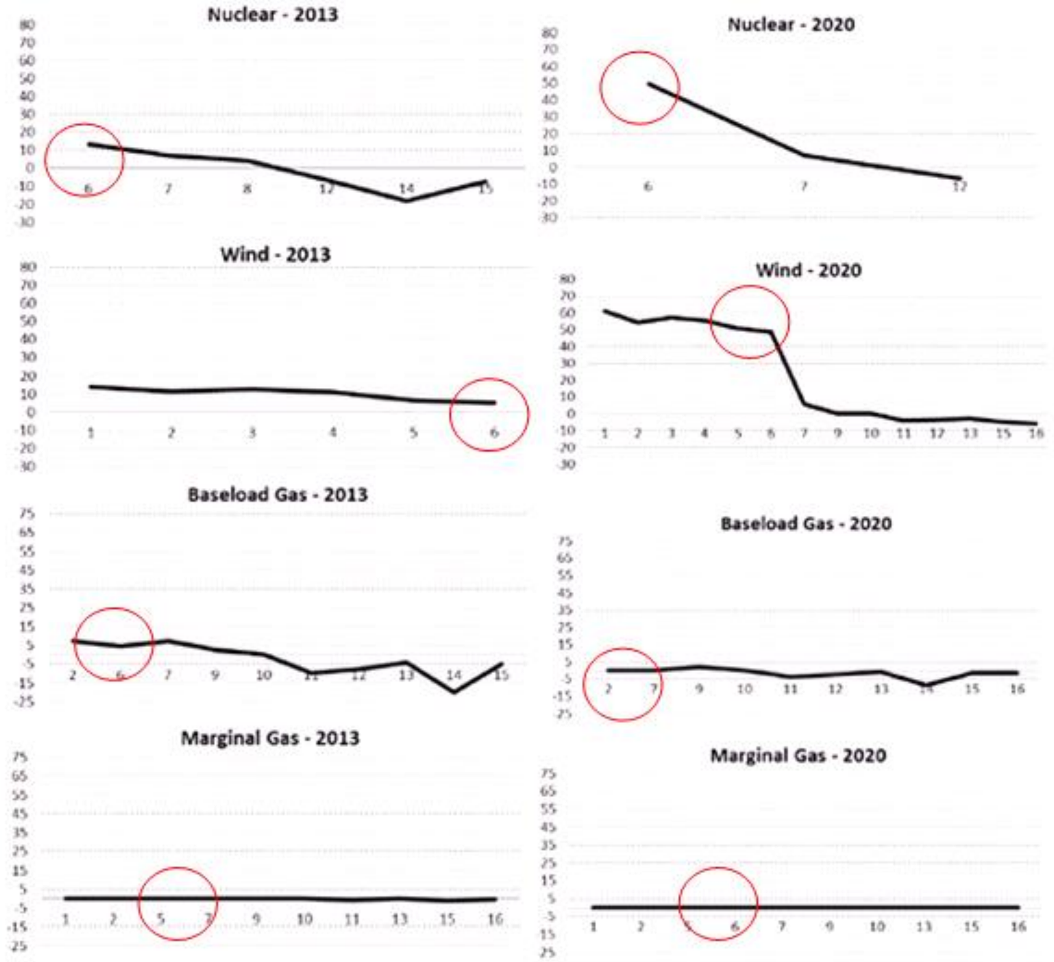
A.48 The workgroup also engaged in additional discussion and consideration of separate modelling work carried out by NERA and Imperial College on behalf of RWE during CMP213. This workgroup discussion went beyond the pre send back discussion of this material which the Workgroup had previously considered and is included in the CMP268 FMR. Importantly, the proposer was asked the additional question regarding what this NERA analysis showed with regard to the cost caused by wind generators as compared with the cost caused by plant classed as Conventional Carbon. The proposer responded by explaining that the NERA analysis did show that in later years (2020 and 2030), as the concentration of wind is expected to increase, the NERA/ICL modelling did demonstrate a divergence between the cost caused by CCGT (Conventional Carbon) as compared with wind (Low Carbon) because the cost caused by wind increased to become substantially greater than the cost caused by CCGTs. The description and graphs below describe this point made by the proposer.

A.49 The Proposer explained that NERA and Imperial carried out analysis using power market modelling to provide a view of the LRMC of transmission network investment caused by different types of generator at different locations. Baringa carried out a review of this analysis at the time of CMP213 (Section 3.3. CMP213: further analysis and review of consultation responses, Further analysis of CMP213 options, and review of NERA/ICL and Pöyry responses to CMP213 Consultation for Ofgem, April 2014) and, reached a conclusion which agreed with Ofgem's comments in the CMP213 Decision letter that the NERA work over stated the LRMC because NERA assumed that the marginal cost of network investment in Scotland would always be expensive HVDC and disregarded the likelihood that there may be other cheaper options available. However, irrespective of this issue, this NERA analysis can be useful for CMP268 with regard to considering how the relative cost of LRMC caused by different types of plant changes when the concentration of Low Carbon generation changes . The proposer identified key observations which can be taken from this NERA analysis from the graphs presented (key data points annotated with a red circle) and described below.

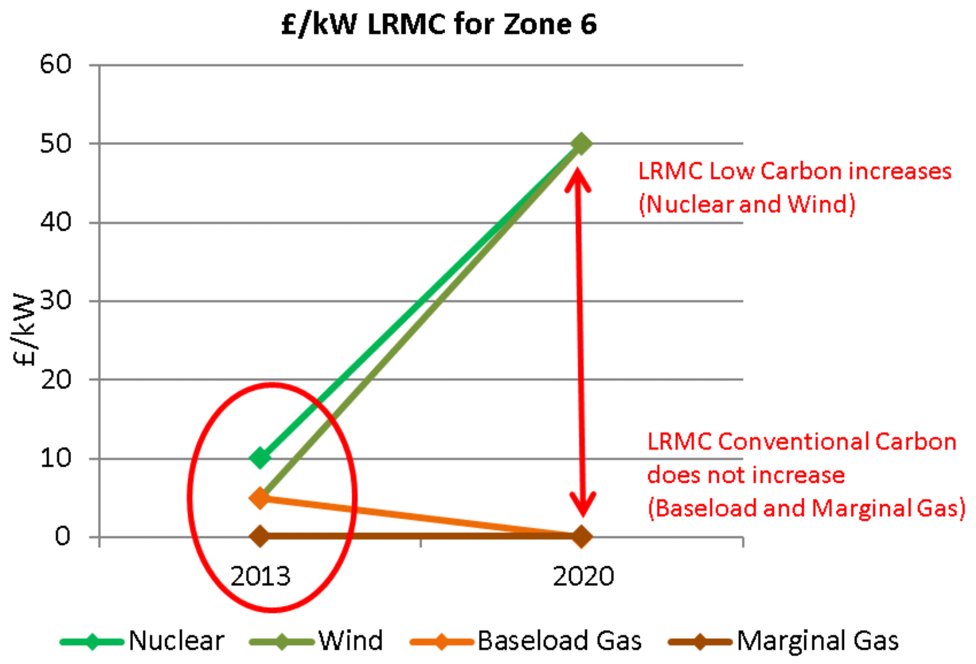
A.50 Graphs for system conditions in 2013 with relatively high diversity (graphs shown below on left hand side) - The relative LRMC of the different types of generator are roughly in proportion to their load factors. For example, considering zone 6, nuclear has the highest load factor and it also has the highest LRMC, baseload gas and wind have very similar LRMC, while marginal gas is the lowest for both load factor and for LRMC. This result is consistent with CMP213 and remains consistent with CMP268 because CMP268 does not make any change to the way tariffs are calculated in circumstances where there is a relatively low concentration of Low Carbon generation.

A.51 Graphs for expected system conditions in 2020 with relatively low diversity (graphs shown below on right hand side) – For northern zones, the relationship between LRMC of different types of generators is shown to be completely different from 2013 in a way which is consistent with CMP268, but not consistent with Baseline. For 2020, this shows the relationship between relative LRMC and relative load factors breaks down and instead, the relative LRMC of different types of generator is driven more by their classification according to “Carbon” versus “Low Carbon” instead. Considering Zone 6 again, this shows that the LRMC of nuclear and wind both increase substantially and become roughly the same as each other despite having very different load factors, which is consistent with both CMP213 and CMP268 due to continuing to apply the Year Round Not Shared tariff to 100% of TEC for Low Carbon plant which is unchanged from Baseline in this regard. CMP268 is the same and does not implement any change compared with Baseline in this regard. However, by contrast, the analysis shows that LRMC of baseload gas (Conventional Carbon) changes in the opposite direction and actually reduces to becomes much closer to that of marginal gas (Conventional Carbon). Most importantly, this analysis clearly shows the divergence in cost between Conventional Carbon generators (both baseload gas and marginal gas) compared with the cost of Low Carbon generators (wind and nuclear) when the system becomes increasingly dominated by wind and diversity reduces. Baseline is clearly not consistent with this result of divergence because it fails to reflect this difference in cost between Low Carbon and Conventional Carbon and instead treats Conventional carbon as if it causes the same cost as Low Carbon. This cost relationship is substantially better reflected by the treatment of Conventional Carbon regarding the YRNS tariff under CMP268 than how this Conventional Carbon is treated under Baseline.

A.52 The graphs below are taken from figures 5.1 and 5.2 showing the LRMC estimates in £/kW for wind, nuclear, baseload gas and marginal gas (Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, Prepared for RWE npower, 21 February 2015, NERA Economic Consulting and Imperial College London).



A.53 A summary extract of part of the NERA/ICL DTIM results is illustrated by the graph below. The Proposer explained that this shows the resulting modelled £/kW LRMC for different types of plant in zone 6 for the two different years of 2013 (during which diversity was relatively high) compared with 2020 (during which diversity is expected to be relatively low). The data was taken from the data points identified by the red circles in the graphs above so that they can be more clearly compared on a single graph. The underlying data was not available, so this was read from the graphs.



A.54 This result was described in the original NERA/ICL report in section "5.2.1. Estimating LRMC" as follows:

"***The high LRMCs for wind in the Scottish zones reflect the fact that, on the margin, additional wind generators in Scotland trigger the need for more reinforcement of the key north-south transmission lines, in particular the HVDC bootstraps****, and so the cost of these bootstraps is reflected in the LRMC estimated for Scottish wind farms in 2020 and 2030;*

Our estimated LRMCs for nuclear generators in the Scottish zones also increase materially in the 2020 and 2030 cases, as they also rise to reflect the cost of reinforcing the Scotland-England/Wales boundaries using the HVDC bootstraps. *By 2030, the "gone-green" generation background does not assume any nuclear capacity will be located in Scotland (see Table 3.2). LRMCs for nuclear plants in England and Wales are relatively low and (in all cases but zone 12 in 2020) positive;*

In contrast to wind and nuclear, our LRMC estimates for Scottish peaking ("marginal gas") plants do not rise to a level that reflects the capacity cost of the bootstraps*. This reflects the fact that peakers tend to generate in low wind conditions, when the capacity built to transport output from Scottish wind farms to southern load centres (i.e. on the HVDC bootstraps) is not constrained, and thus* ***these plants are not adding to transmission capacity costs on these boundaries. In fact, as the north-south transmission lines are reinforced to accommodate growth in generation capacity (especially wind) in Scotland, the LRMCs of Scottish peakers fall as there is more spare transmission capacity in high demand, low wind periods when those peakers are most likely to generate****. The LRMC of accommodating incremental peaking plants in English and Welsh zones is also close to zero, suggesting that peaking* *plants add very little to transmission reinforcement requirements, irrespective of their location;*

*We find a similar result for gas plants operating at higher load factors ("baseload gas"). These plants add very little to transmission reinforcement costs if they are located in England or Wales, but also **impose a much lower LRMC of transmission than wind farms or nuclear plants in Scotland**. This is because, at times when north-south transmission lines are likely to be constrained (high wind conditions), our modelling suggests these plants are likely to be out of merit. In some cases, it is possible that the model is choosing to constrain down thermal plants in Scotland before curtailing wind output when north-south transmission lines are becoming constrained. However, the effect is the same; they are not running when the lines are constrained, so are not adding to the infrastructure costs incurred to accommodate them. In other words, because it is cheaper to constrain them down than to build additional capacity to accommodate their output, their presence on the system in Scotland is not adding to transmission investment costs, and is not reflected in LRMC*."[emphasis added] (5.2.1. Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA/Imperial College, February 2014.

A.55 **Explanation regarding why the Negative Year Round not shared tariffs arise from a defect caused by an artefact of the way parallel circuits are treated**

A.56 Following Workgroup discussion of this issue, National Grid carried out additional analysis of the ICRP Transport model outputs and provided this evidence to the Workgroup. This evidence showed that in practice, all circuits classed as "Year Round" with a negative tariff are actually fully shared. Therefore in practice there is full sharing taking place of all the relevant Year Round MWkm for those zones.

A.57 This is illustrated by the table below which shows the genuine diversity of parallel zones 22, 23 and 24 highlighted in yellow as exhibiting 100% diversity.

A.58 For the avoidance of doubt, all zones which exhibit a negative Year Round tariff (National Grid published 5 Year Forecast Feb 2017) are shown as fully shared in the table below. This includes zones 16, 19, 20, 21, 22, 23, 24, 25, 26, 27.

Zone	Zonal Carbon	Low Carbon	Cumulative Carbon	Low Carbon	Total Gen	Diversity
2	400	0	400	0	400	100.00%
1	300	744	700	744	1,444	96.96%
4	0	41	0	41	41	0.00%
3	0	485	700	1,270	1,970	71.06%
5	0	553	700	1,823	2,523	55.49%
6	0	64	700	1,886	2,586	54.13%
8	440	80	1,140	2,132	3,272	69.68%
7	0	166	0	166	166	0.00%
9	120	25	1,260	2,157	3,417	73.74%
10	80	2,426				
11	0	2,618				
10/11	80	5,044	1,340	7,202	8,542	31.38%
12	0	309	1,340	7,511	8,851	30.28%
13	542	1,207				
14	155	4,079				
13/14	697	5,286	2,037	12,797	14,834	27.46%
15	9,044	425	11,081	13,222	24,303	91.19%
19	1,644	0	1,644	0	1,644	100.00%
16	12,150	828	24,875	14,050	38,925	100.00%
17	1,944	1,221	26,819	15,271	42,090	100.00%
18	3,567	2,535	30,386	17,806	48,192	100.00%
22	1,234	0				
23	0	0				
24	9,180	2,021				
22/23/24	10,414	2,021	40,800	19,827	60,627	100.00%
20	2,199	0	2,199	0	2,199	100.00%
21	3,384	228	5,583	228	5,811	100.00%
27	1,045	0	1,045	0	1,045	100.00%
26	1,078	1,061	2,123	1,061	3,184	100.00%
25	1,970	400	1,970	400	2,370	100.00%

A.59 National Grid explained that the presence of negative YRNS tariffs found in zones 22 and 23 is caused by a formula effect regarding the way the Year Round MWkm of parallel zones are treated. Parallel zones are zones where the ICRP load flow model calculates the flow on a parallel basis i.e. these zones are located beside each other instead of being one behind the other in series. To understand why this formula affect occurs, it is necessary to understand three key elements which arise from the ICRP Transport model as specified in the table above:

1. “Unadjusted Transport Zonal Wtd Marginal (km)” This represents the total incremental Year Round MWkm for a each zone as calculated y the ICRP Transport model.

2. “Shared Transport Zonal Wtd Marginal (km)” This represents the MWkm for each zone which the TNUoS charging model deems by to be shared based on the degree of diversity. If there is a less than 50% concentration of Low Carbon, then the model assumes that Diversity is 100% and therefore 100% of the Year Round circuits are classed as “shared”

3. "Not shared Transport Zonal Wtd Marginal (km)" This represents the MWkm for each zone which the TNUoS charging model calculates to be not shared. The Transport model calculates this on a residual basis by starting with the model calculated total "unadjusted" MWkm and deducting the deemed "not shared" MWkm.

A.60 The National Grid spreadsheet showed that the reason why this relationship breaks down for parallel zones is that the as would be expected, the ICRP Transport Model calculates the total "unadjusted" MWkm separately for each parallel zones, so for example parallel zones 22, 23 and 24 exhibit different total "unadjusted" MWkm. However for tariff purposes the TNUoS Tariff Model deems the total length of MWkm in each of the parallel circuits to the maximum km out of all of the parallel circuits. In this example, Zone 24 has the largest total km at positive 88.29 while the other two zones parallel to it (zone 22 and zone 23) exhibit the opposite sign of negative total km. So in effect, in this example, the model takes the highest positive km from zone 24 and uses this to replace the modelled negative total km in zones 22 and 23

A.61 When the Tariff model then calculated the "Shared" MWkm for each fully shared parallel zone, this becomes equal to the **same absolute length as the longest "shared" km out of all of the different zones which are parallel to each other** and **in doing so the model reverses the sign of the "shared" tariff for Zones 22 and 23 to be positive when they should be negative**. It then follows that when the "not shared" km are calculated for each of the three parallel zones the then for Zones 22 and 23, the calculation deducts the positive "shared" km (calculated from the total km from zone 24) from the original negative total "unadjusted" km calculated by the ICRP Transport model for each zone, so for Zones 22 and 23 it calculates a length of "not shared" km which is even longer (even more negative) than the ICRP Transport Model calculated total "unadjusted" km for those zones. This is shown by the example calculation which explain the numbers in the table below.

	Zone 22 Cotswold	Zone 23 Central London	Zone 24 Essex and Kent
Transport model calculated total km	-160.98	-136.25	88.29
Tariff model assumed total km	88.29	88.29	88.29
Tariff model calculated degree of sharing	100%	100%	100%
Tariff model calculated shared km (used for YRS tariff)	88.29	88.29	88.29
Tariff model calculated not shared km (used for YRNS tariff)	-249.26	-224.54	0.00

A.62 The table below demonstrates that if 100% of Year Round km for zones 22 and 23 were classed as "shared", which in practice they are, then 100% of the Year Round tariff would be classed as "shared", while the Year Round "not shared" tariff for those zones would be zero.

	Zone 22 Cotswold	Zone 23 Central London	Zone 24 Essex and Kent
Transport model calculated total km	-160.98	-136.25	88.29
Tariff model assumed total km	-160.98	-136.25	88.29
Tariff model calculated degree of sharing	100%	100%	100%
Tariff model calculated shared km (used for YRS tariff)	-160.98	-136.25	88.29
Tariff model calculated not shared km (used for YRNS tariff)	0.00	0.00	0.00

A.63 The result that the Baseline charging methodology calculates for some zones a negative Year Round Not Shared tariff even though 100% of the km in those zones are fully shared implies that this may have identified an new and different additional defect which may warrant consideration by a future modification proposal.

Annex 2 – Presentation from National Grid representative from CMP213 workgroup

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CMP268 – Overview of CMP213

20th February 2017

Ivo Spreeuwenberg

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Agenda

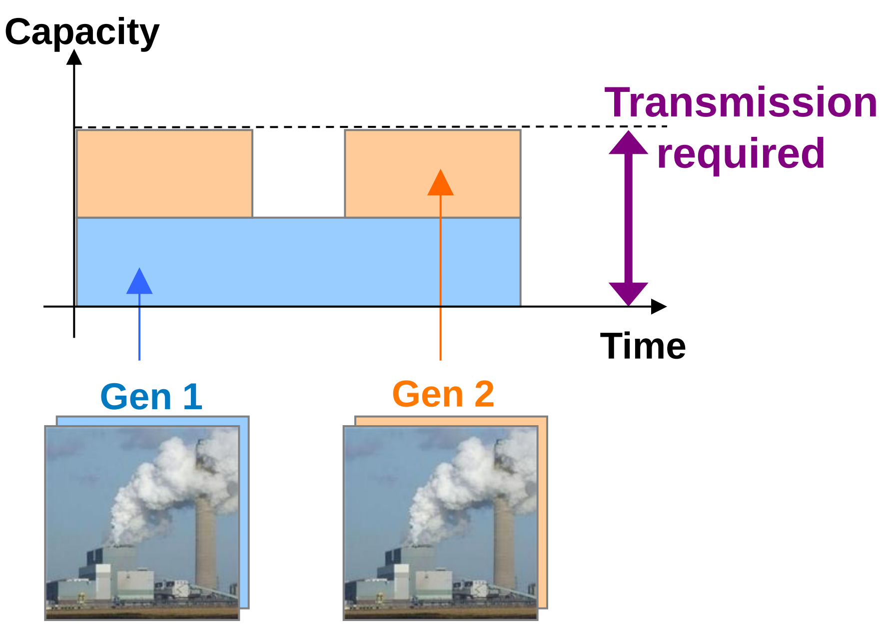
TNUoS

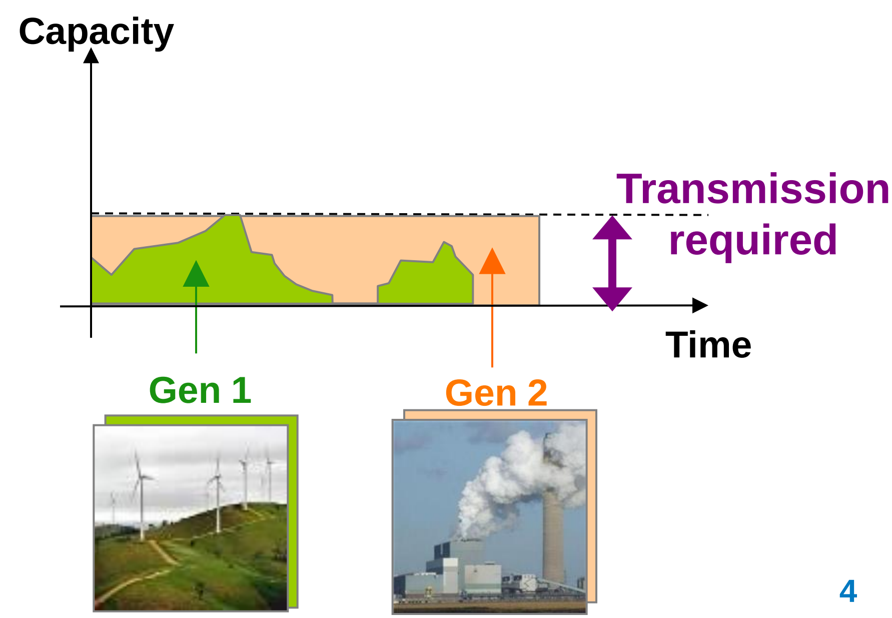
1. Collect revenue on behalf of transmission companies
2. Effective Competition
   - Transparency
   - Stability
   - Simplicity
   - Predictability
3. Reflect costs – long run, forward looking
4. Take account of developments in transmission business
5. Non-discrimination

How to effectively balance (2) and (3)?

Capacity Sharing – Background

- Not all users drive the same requirement for investment
- TAR focus on connection timing; models reflecting network usage not taken forward
- Is there a proxy that could be included in charges?





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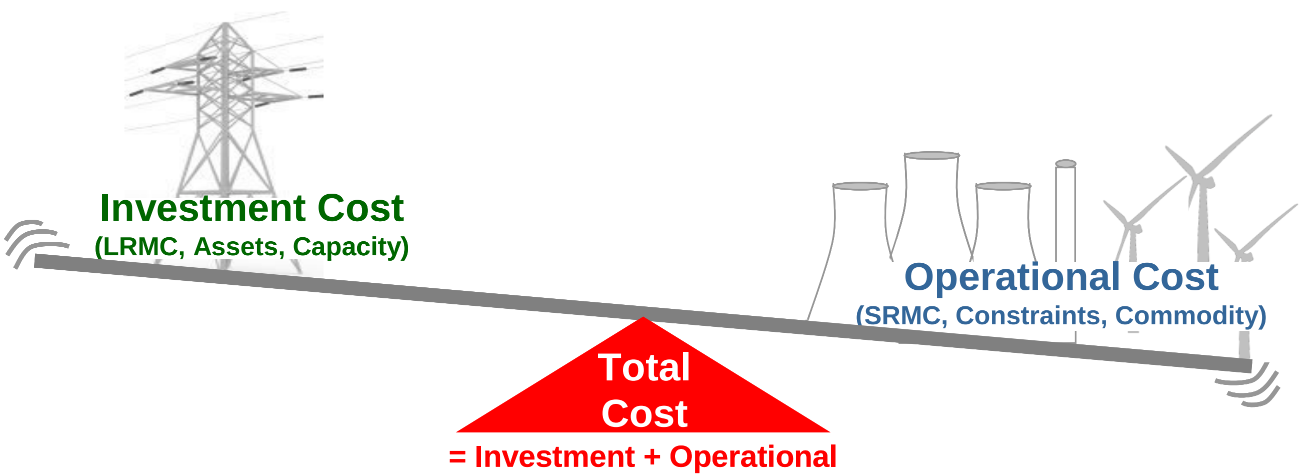
Capacity Sharing – Background

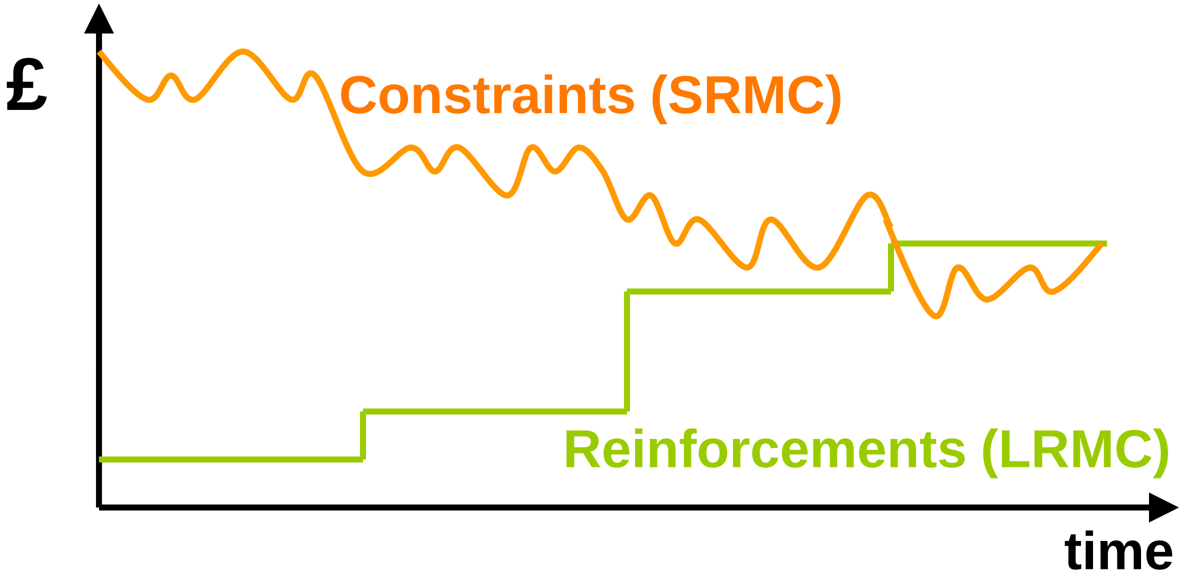
- Network capacity vs. future savings in operational costs
- Some investment remains demand security driven



- Charging methodology should develop to reflect
- Must remain simple, transparent and non-discriminatory
- Use long term convergence of LRMC and SRMC

Capacity Sharing – Background

- Explicit information is not available (TAR)
- Implicit assumptions must be made
- For investment driven by “year round” conditions, these should reflect assumptions made in cost benefit analysis



- TSOs incentivised to balance SRMC and LRMC

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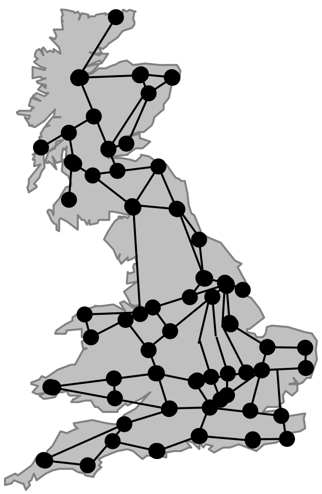
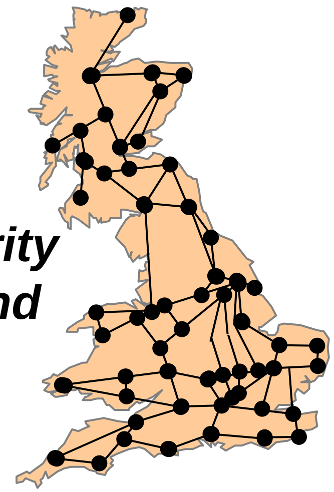
Transport model changes to reflect NETS SQSS evolution

Transport Model:



Existing Transport Model

Peak Security Background



Generator Type	Background
Intermittent	0%
Controllable	variable

Year Round Background

Generator Type	Background Setting
Intermittent	70%
Nuclear & CCS	85%
Interconnectors	100%
Hydro	variable
Pumped Storage	50%
Peaking	0%
Other (conventional)	variable

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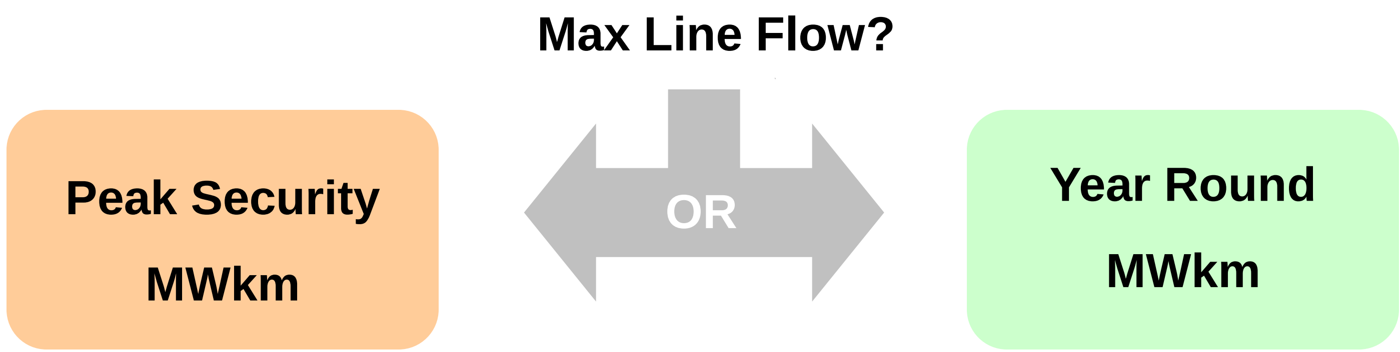
Two backgrounds resulting in 3 tariff components

Tariff Model:

- Revised model allocates circuits to a given background



- Calculates three tariffs

Tariff calculation evolved through TransmiT related processes

i

Conventional Tariff =
Peak Security £/kW + Year Round (Shared) £/kW + Residual £/kW

Intermittent Tariff =
Year Round £/kW + Residual £/kW

ii

Conventional Tariff =
Peak Security £/kW + (Year Round (Shared) £/kW X Load Factor) + Residual £/kW

Intermittent Tariff =
(Year Round £/kW X Load Factor) + Residual £/kW

iii

Conventional Tariff =
Peak Security £/kW + (Year Round (Shared) £/kW X Annual Load Factor) + Year Round (Not Shared) £/kW + Residual £/kW

Intermittent Tariff =
(Year Round £/kW X Annual Load Factor) + Year Round (Not Shared) £/kW + Residual £/kW

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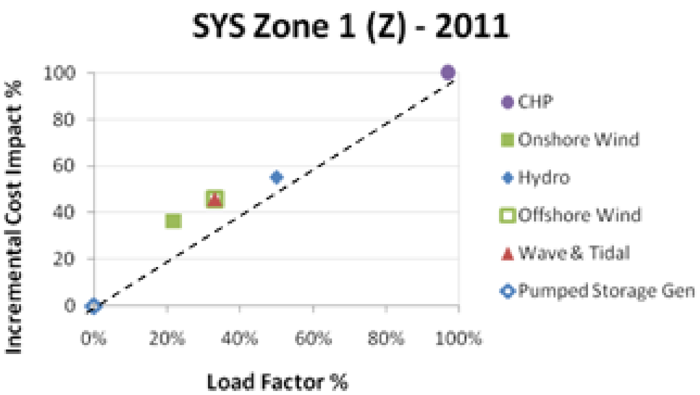
TransmiT related timeline

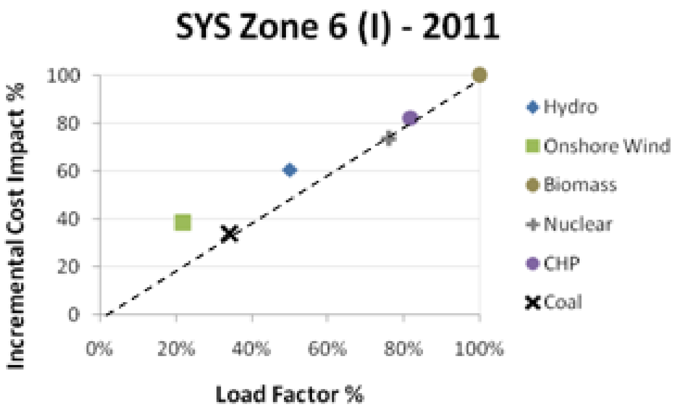
Review of Intermittent Generation Charging (GB ECM-25)	June '10	i
Call for Evidence and Academic Reports	Oct. '10 – June '11	
Industry Technical WG develop options	July '11 – Oct.'11	ii
Economic Assessment of 3 options	Aug.'11 – Dec.'11	
Ofgem SCR consultation	Dec.'11 – Feb. '12	
Ofgem conclusions and direction to NGET	May'12	
NGET raise CUSC modification proposal (CMP213)	20th June 2012	
CUSC Panel meeting	29th June 2012	
CUSC working group	June '12 – June '13	iii
Ofgem IA and Consultation	August '13	
Further Consultation	April '14	
Decision	July '14	
Implementation	April '16	

Agenda

Annual load factor vs. annual incremental cost

- Original proposes the use of ALF to better reflect impact of generators with different characteristics on incremental cost
- Full market model used to illustrate relationship between these two elements
- Imperfect relationship





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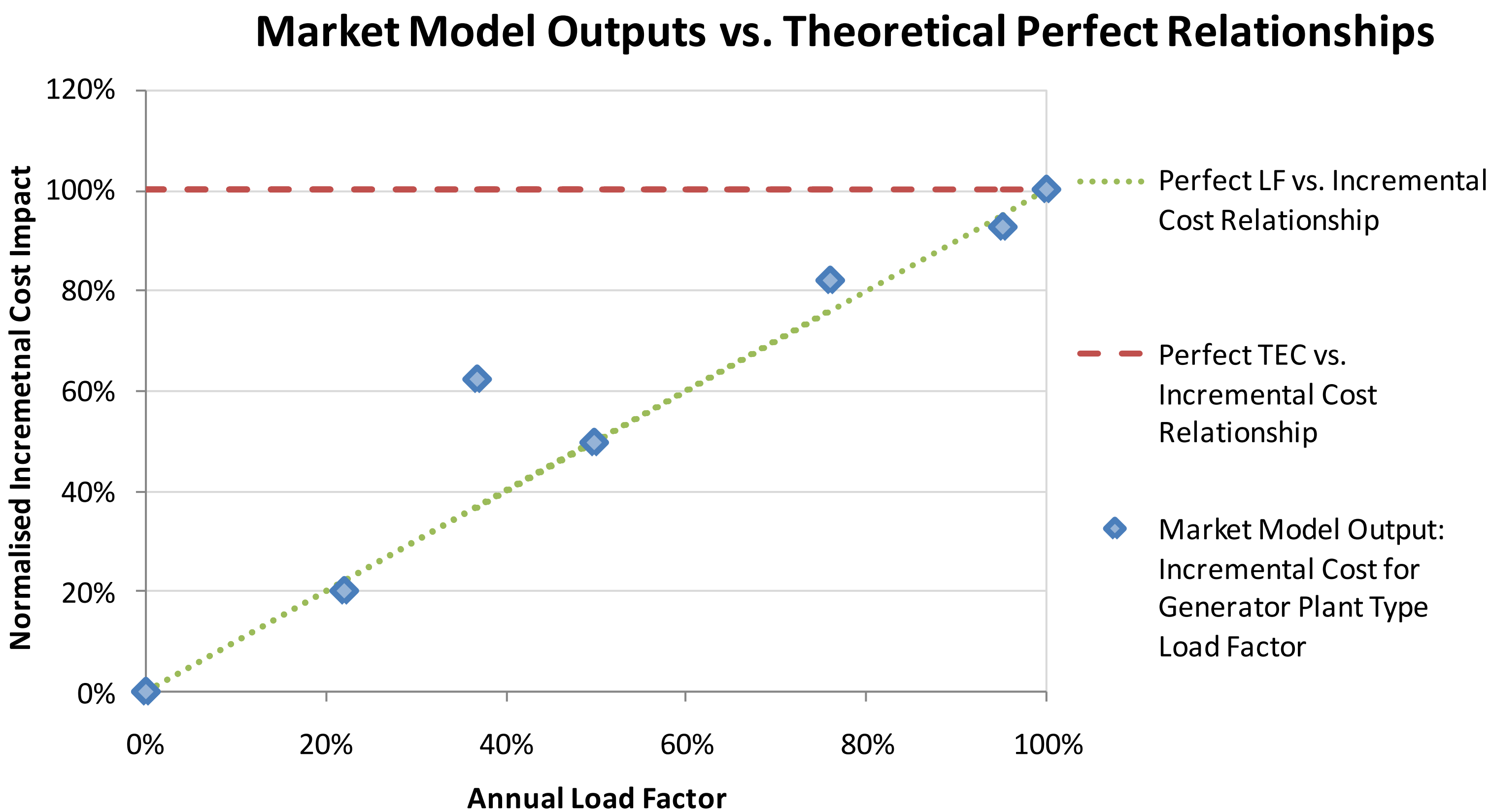
Annual load factor vs. annual incremental cost



- Despite imperfections the Proposer’s view is that it is more cost-reflective than charging on TEC alone and remains relatively simple

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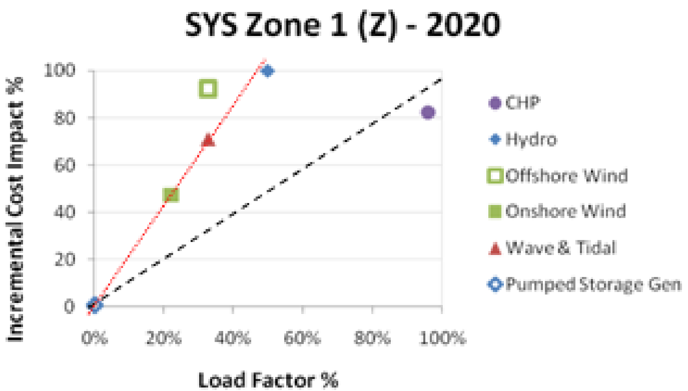
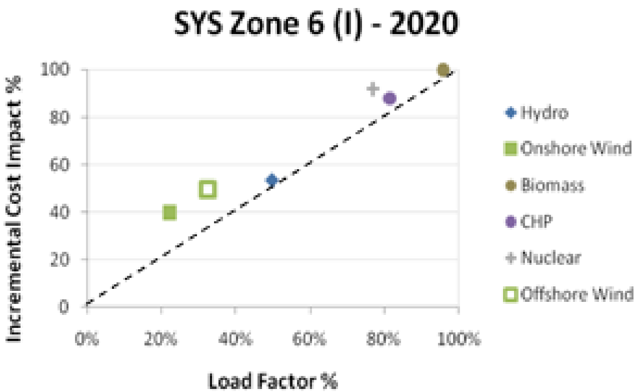
Annual load factor vs. annual incremental cost

- Analysis undertaken in two separate market models to further test relationship
- Workgroup agreed that the relationship was an imperfect one, with some believing there was no relationship evident across network
- Significant divergence in the relationship in future years for some areas of the network also identified
- Hypothesis that the cause of this divergence was down to the effect of high bid prices in areas dominated by low carbon plant





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Key elements affecting incremental cost

- Five elements identified as driving incremental constraint costs

Volume of Incremental Constraints (MWh)

i. Generator output over the year

ii. Correlation between generation running within an area

iii. Correlation with constraint times

X

Price of Incremental Constraints (£/MWh)

iv. Bid price of the marginal generator on the exporting side

v. Offer price of the marginal generator on the importing side

- Generator output ~ annual load factor
- Bid and Offer prices investigated in detail
- Correlation elements inherent in market model (granularity of modelling questioned by some)

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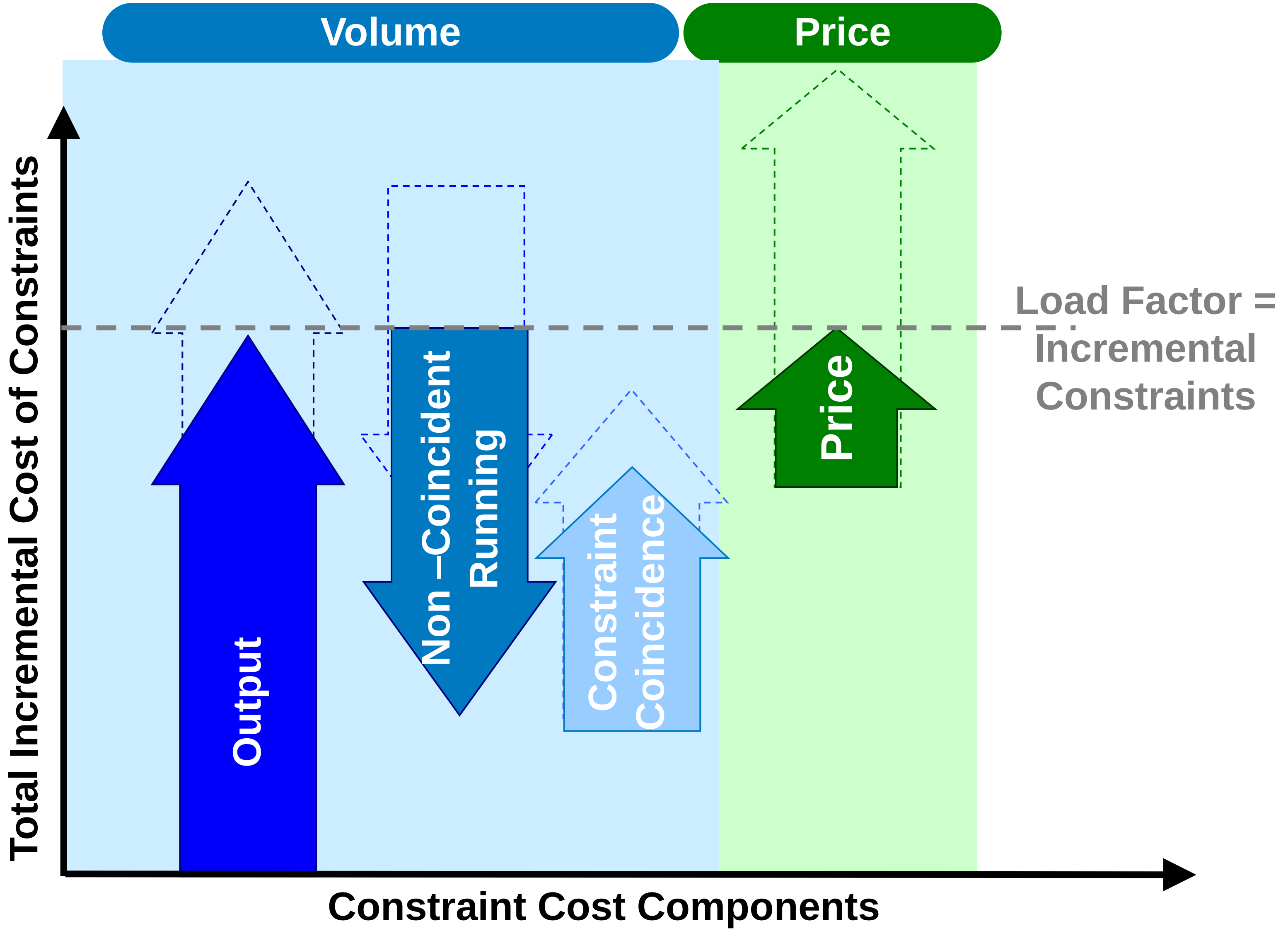
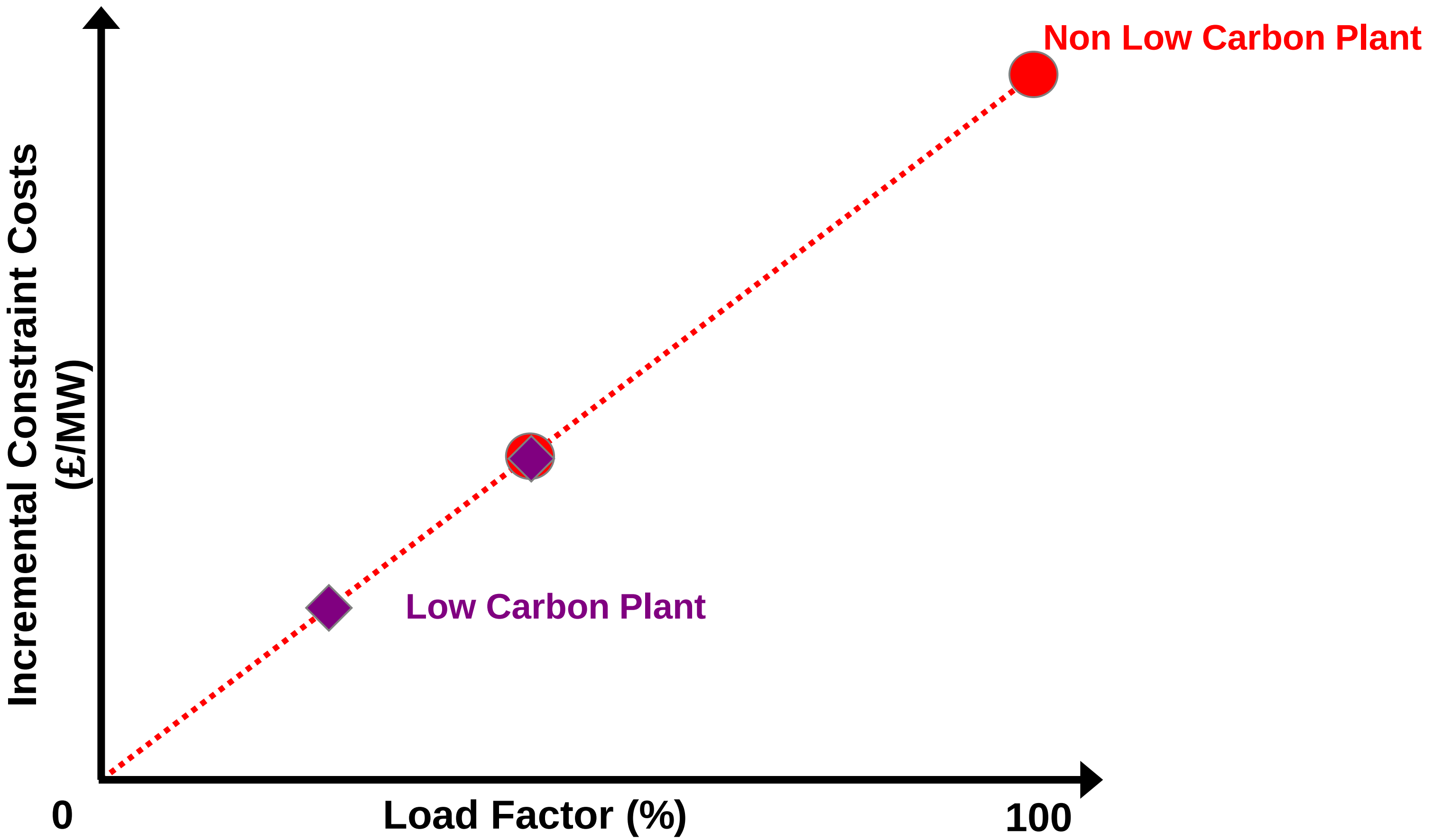
Key elements affecting incremental cost



Good linear relationship where sufficient diversity exists



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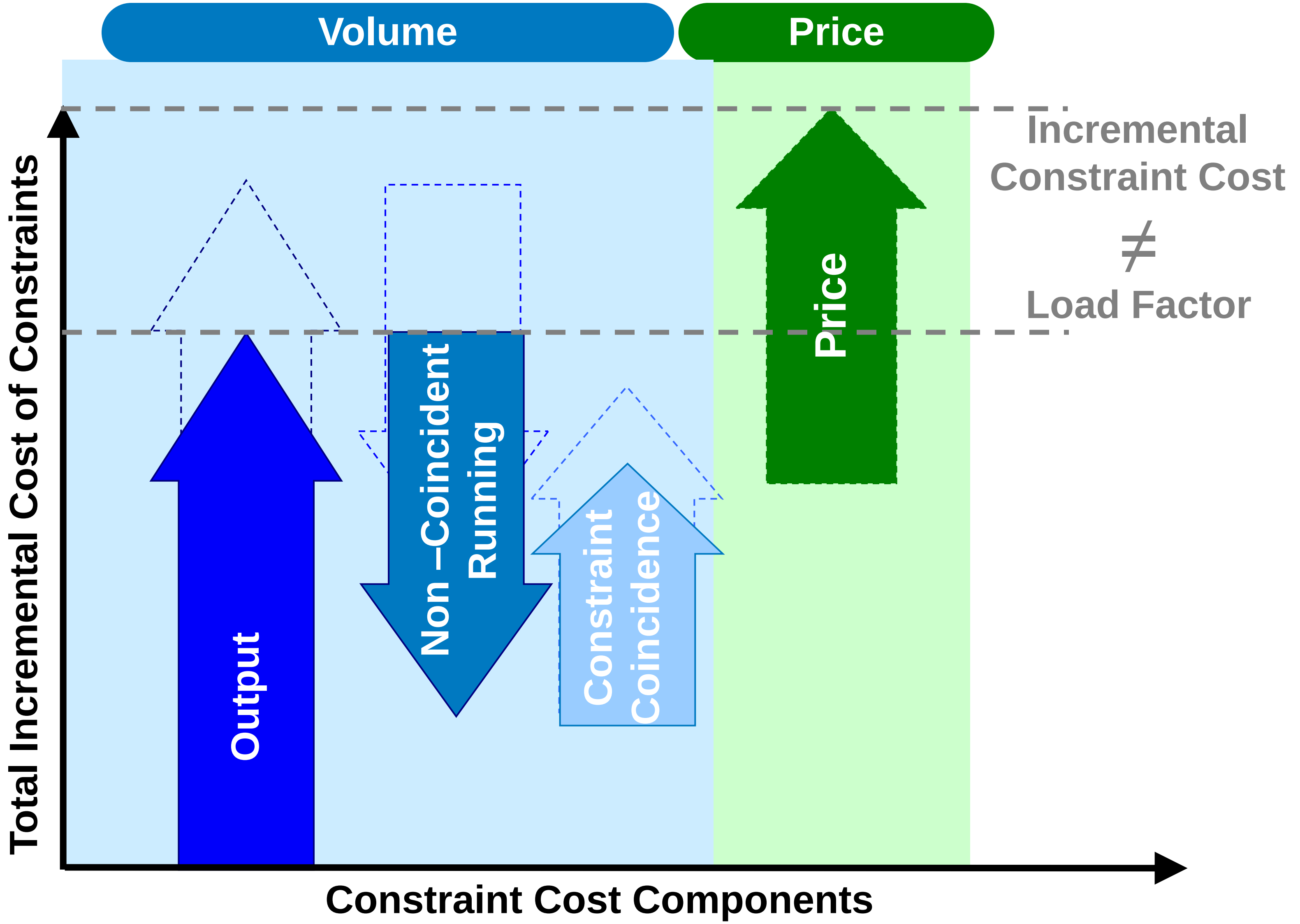
Relationship starts to break down for insufficient price diversity



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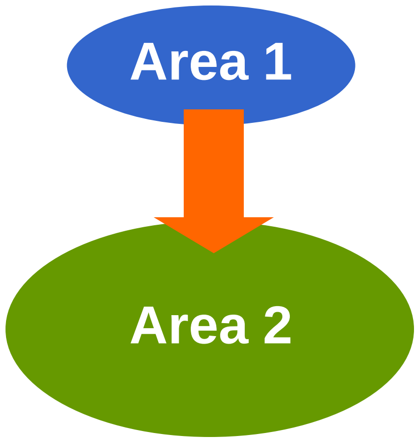
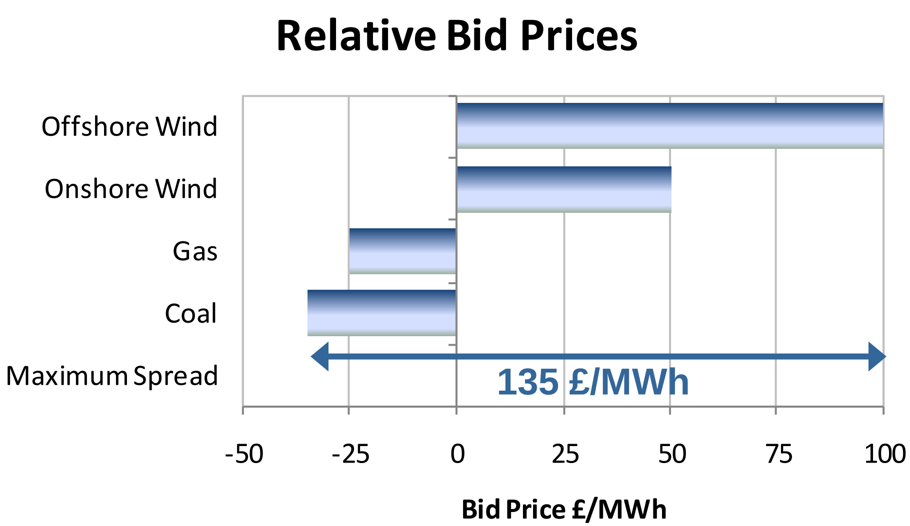
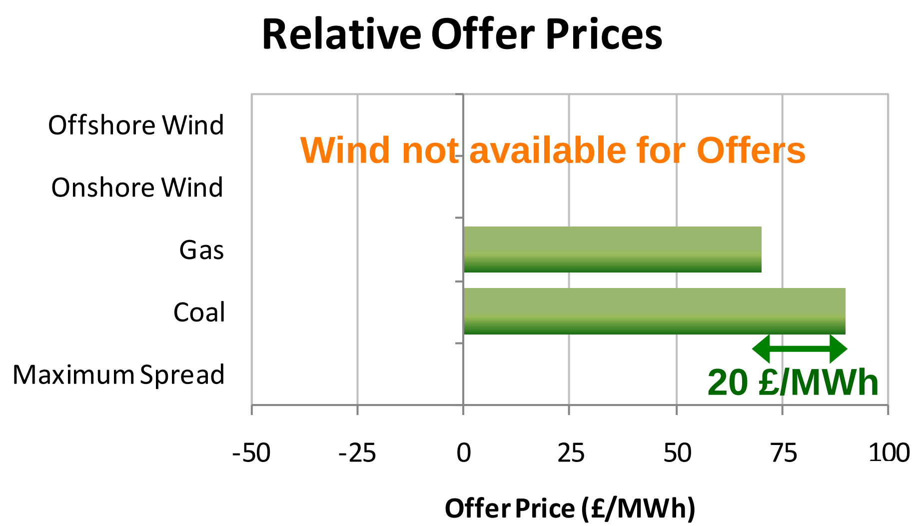
Inspection of prices reveals why bids are most significant



- Bids from Area 1 – *limited* market participants
- Offers from Area 2 – *more* market participants (i.e. more diversity)



Bids from subsidised plant when options limited in Area 1



Offers from marginal plant due to number of options in Area 2

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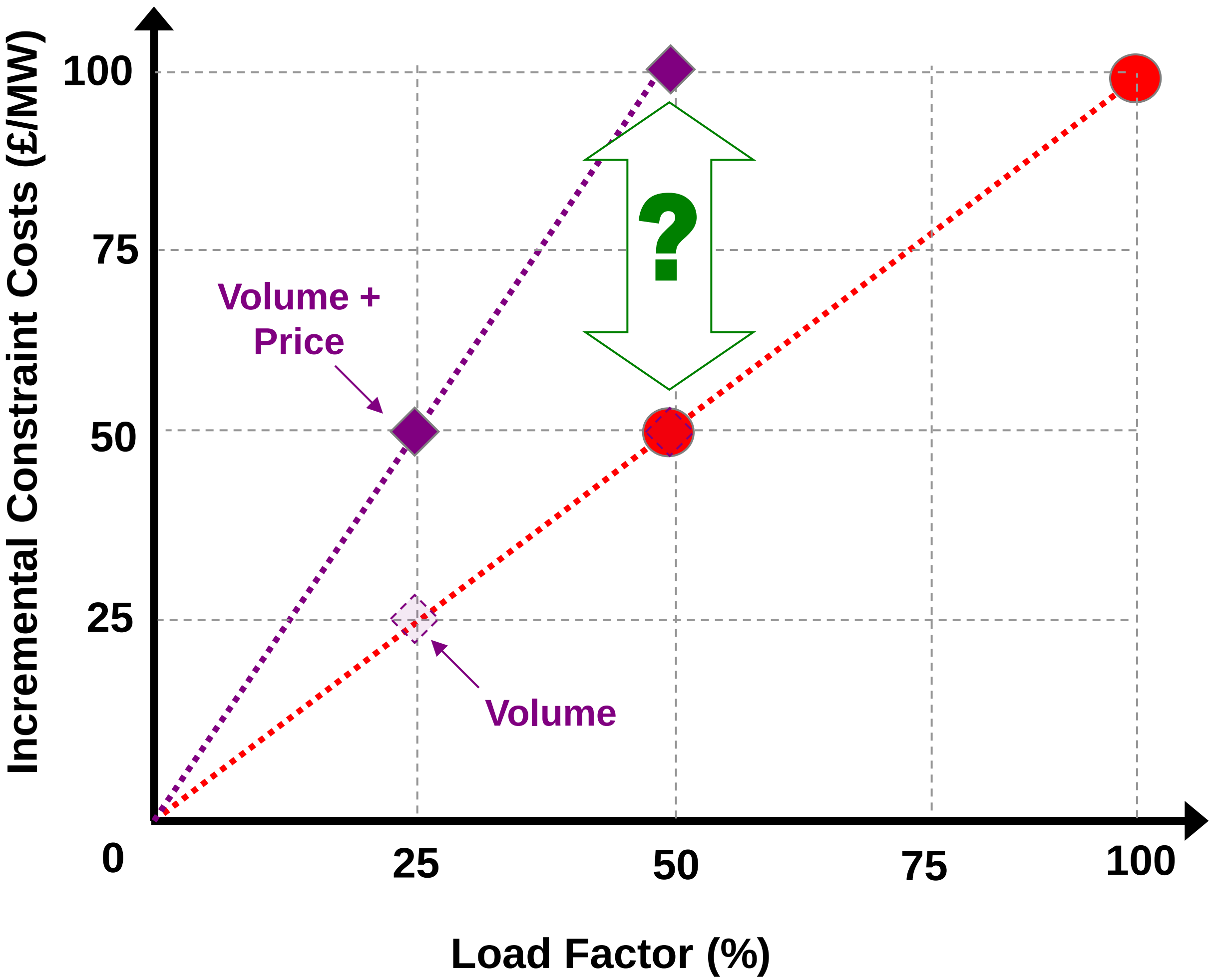
How much diversity is sufficient?



- Is the additional complexity proportionate for the additional cost-reflectivity?

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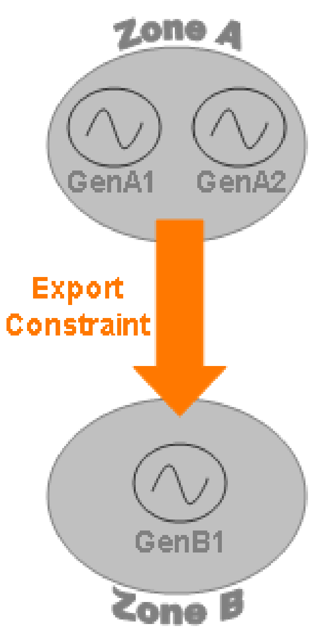
Effects Tested in Market Model

- Maintain unconstrained dispatch from ‘Gone Green’ scenario, but simplify to 2 zone transmission network in order to unpick effects
- Half-way house between ***top down*** full network analysis presented throughout 2011/2012 and ***bottom up*** theory developed by the Workgroup and set out in the consultation



- Method: leave 500MW of generation and consider varying proportions of different plant types and varying boundary capacity into/out of the zone under consideration
  - Onshore Wind + CHP; Export; 2011
  - Onshore Wind + Coal; Export; 2011
  - Onshore Wind + CHP; Export; 2020
  - Onshore Wind + CHP; Import; 2011
  - Onshore Wind + Coal; Import; 2011
  - Onshore Wind + CHP; Import; 2020
  - Offshore Wind + CHP; Export; 2011

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Effects Tested in Market Model

For each scenario:			
Wind MW	Conv. MW		Boundary MW
1	499		
150	350		0
250	250		100
300	200		200
350	150		300
400	100		400
450	50		500
499	1		600

- Each boundary capacity level analysed for each generation background

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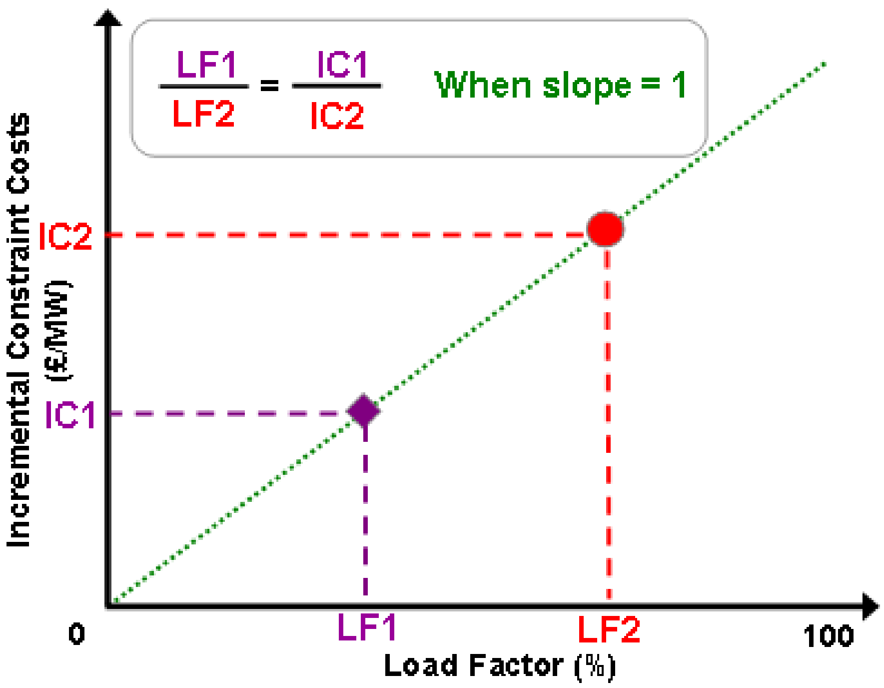
Effects Tested in Market Model

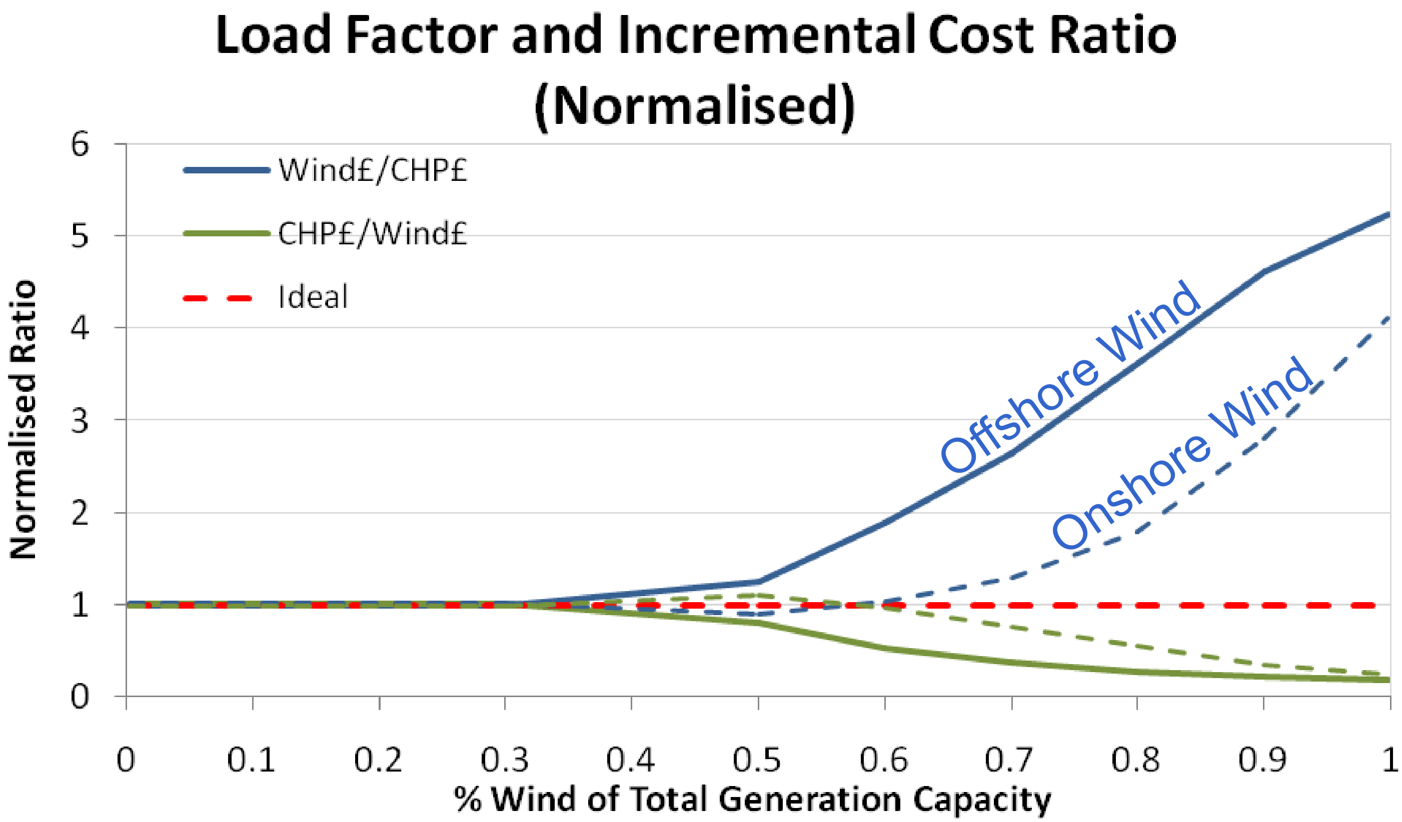


- LF1 = Intermittent (Wind)
- LF2 = Conventional (Coal/CHP)

- Annual incremental constraint costs vary in proportion to annual load factor when:

  slope of line = 1

How much diversity is sufficient?



- Analysis in 2-node model served to corroborate hypothesis and help quantify effect

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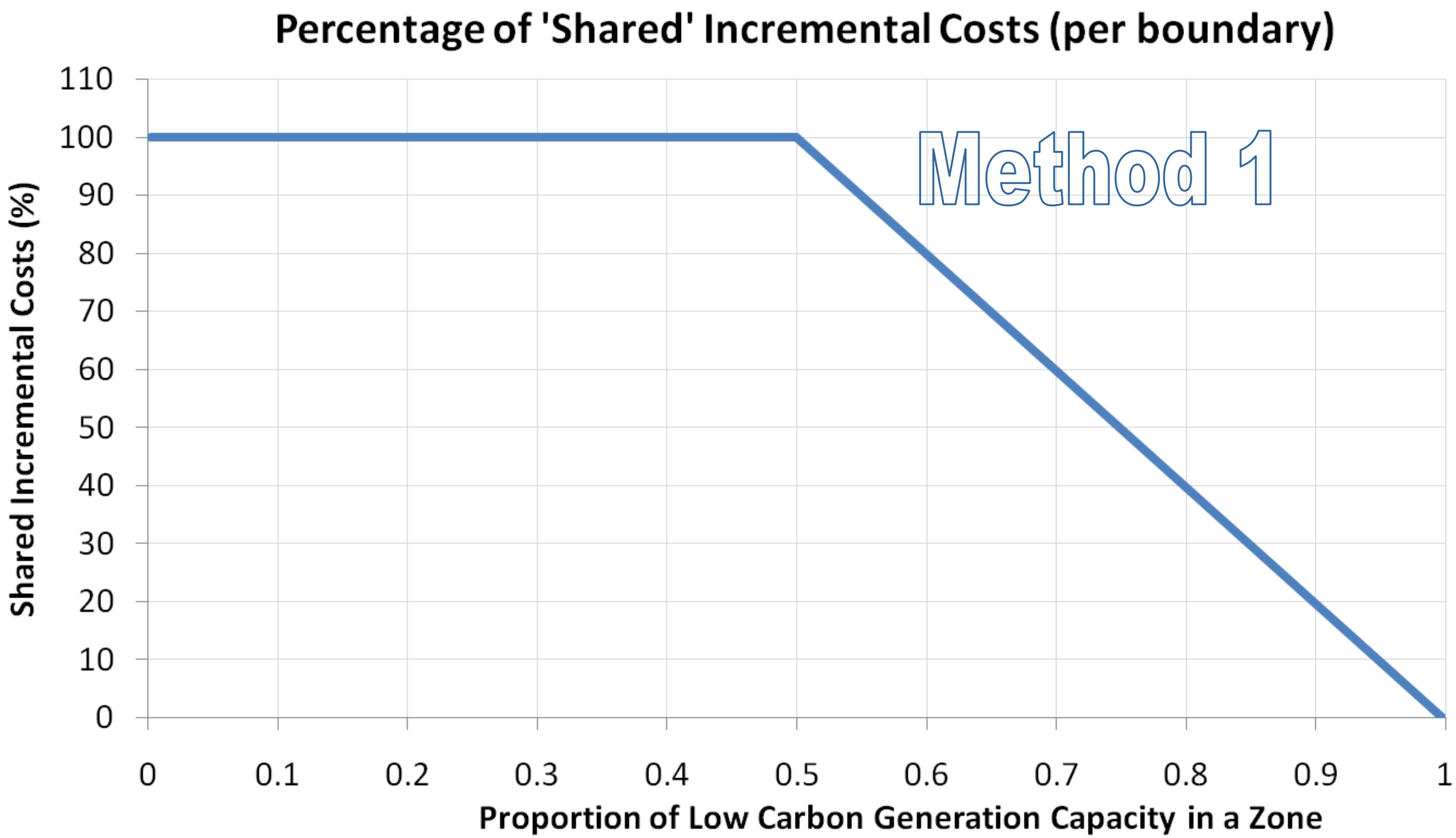
Implementation

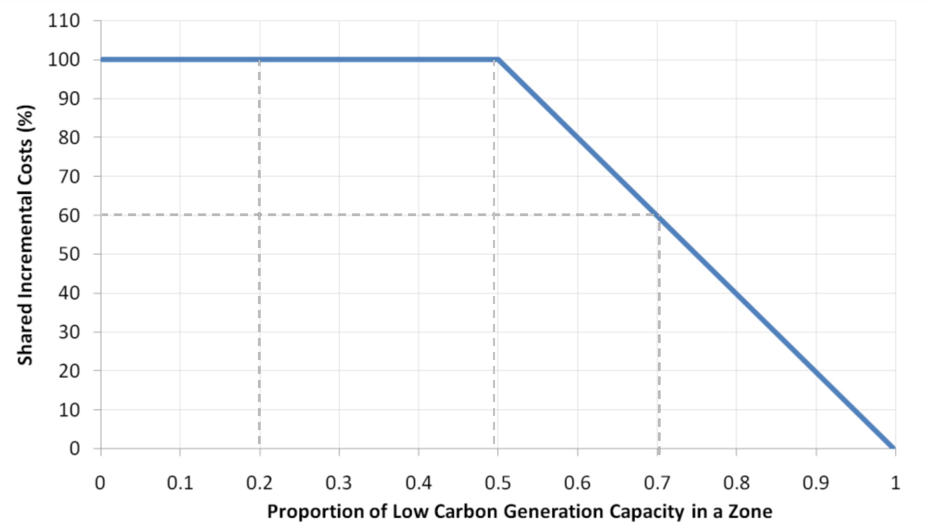


- (YR Shared incremental £/kW) x **ALF** x TEC
- (YR Non-shared incremental £/kW) x TEC

Method 1: Example

	LC/C		Method 1 Shared	Method 1 Non-Shared
Zone A	100/0	100km	0	100
Zone B	70/30	200km	120	80
Zone C	50/50	50km	50	0
Zone D	20/80	100km	100	0
	Ref.			
Total ZA:		450km	270	180

Tariff 270x(ECxSFx)ALFxTEC + 180x(ECxSFx)TEC



Agenda

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CMP213 – Workgroup Meeting 2

24th July 2012

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Generator Specific Assumptions

CBA Inputs:

Gen Unit

- TEC
- Unit Avail.
- Fuel Avail.
- Efficiency

Prices

- Fuel Price
- CO_2 Price
- ROC/FiT Price

BM

- Bid Price
- Offer Price

- Generators unable to provide TSO with information
- Significant complexity

Is there a simple alternative?

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Use of a Simple Market Model

Unconstrained Dispatch

- Fuel Price
- CO_2 Price
- ROC/FiT Price
- Capacity
- Unit Avail.
- Fuel Avail.
- Efficiency
- Demand
- Merit Order

Prices

- Fuel Price
- CO_2 Price
- ROC/FiT Price

Gen. Unit

- Capacity
- Unit Avail.
- Fuel Avail.
- Efficiency

Market

- Demand
- Merit Order

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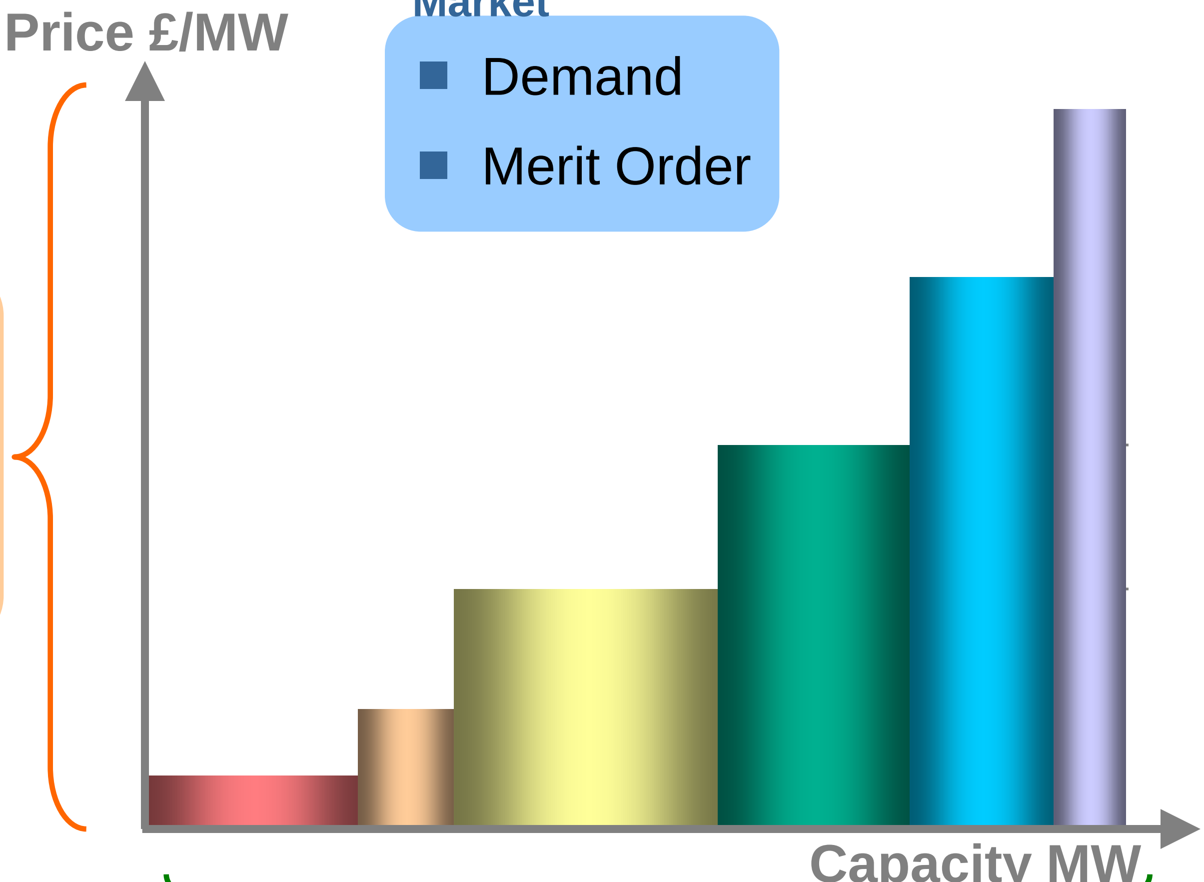
Market Model - Generation Inputs

Market

- Demand
- Merit Order



Prices

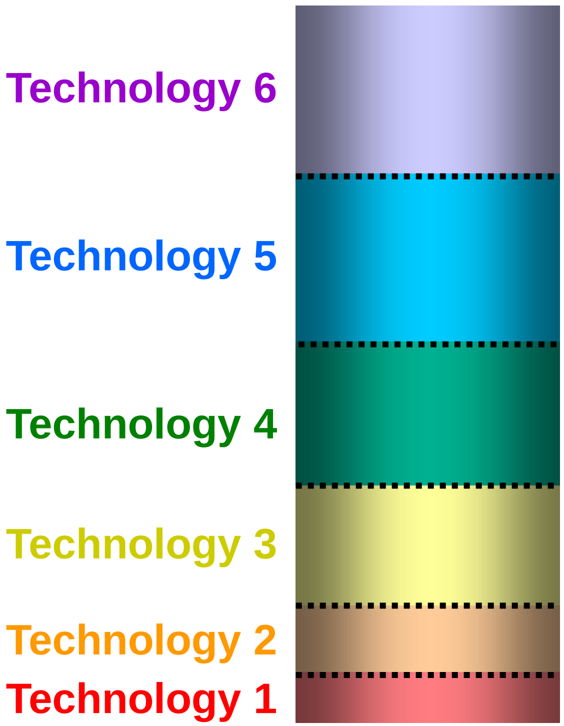
- Fuel
- CO_2
- ROC/FiT

Gen. Unit

- Capacity/MEL
- Efficiency
- Unit Avail.
- Fuel Avail.

Implicit Assumptions

Market Model - Generation Merit Order



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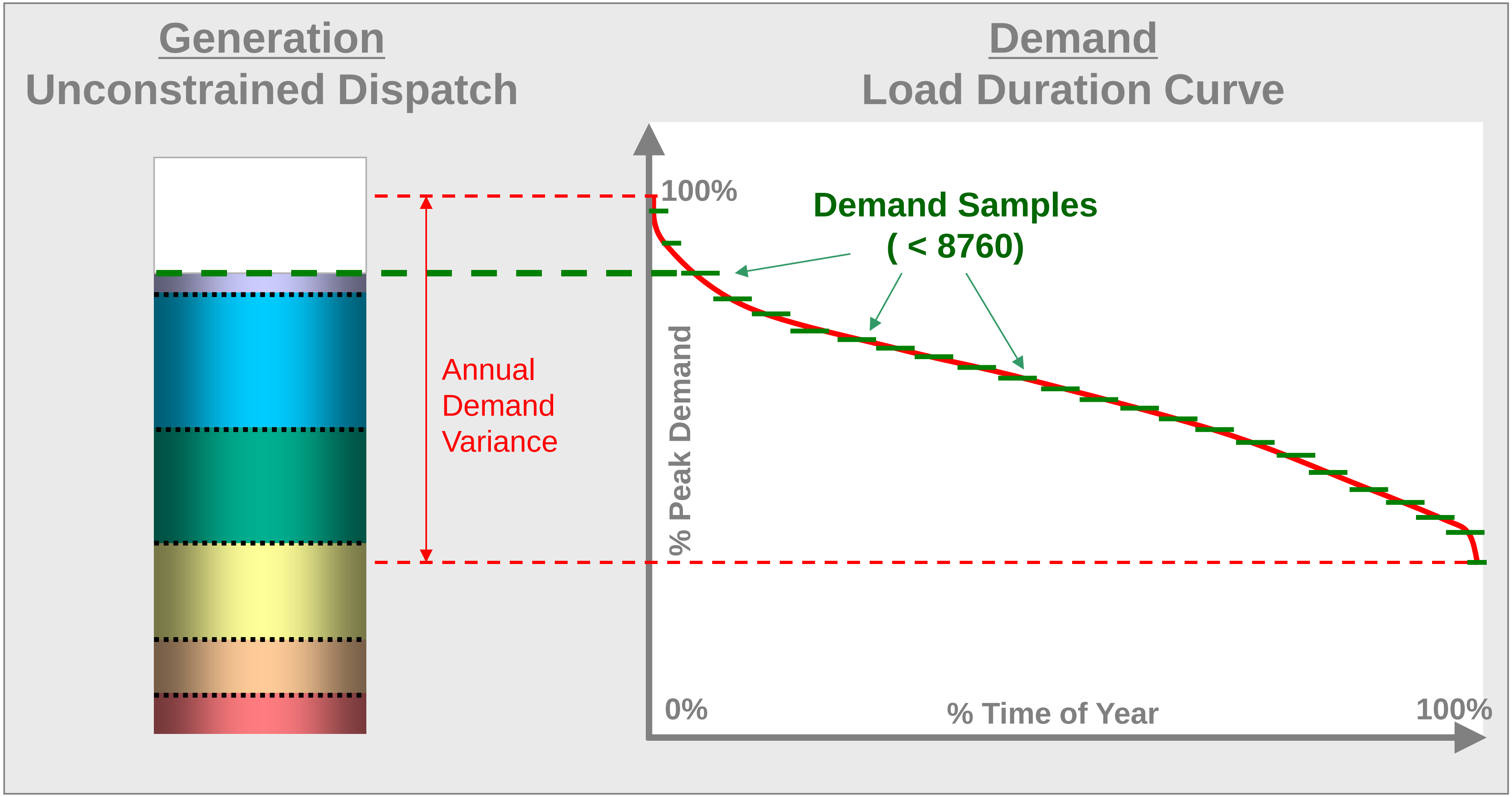
Market Model - Unconstrained Dispatch



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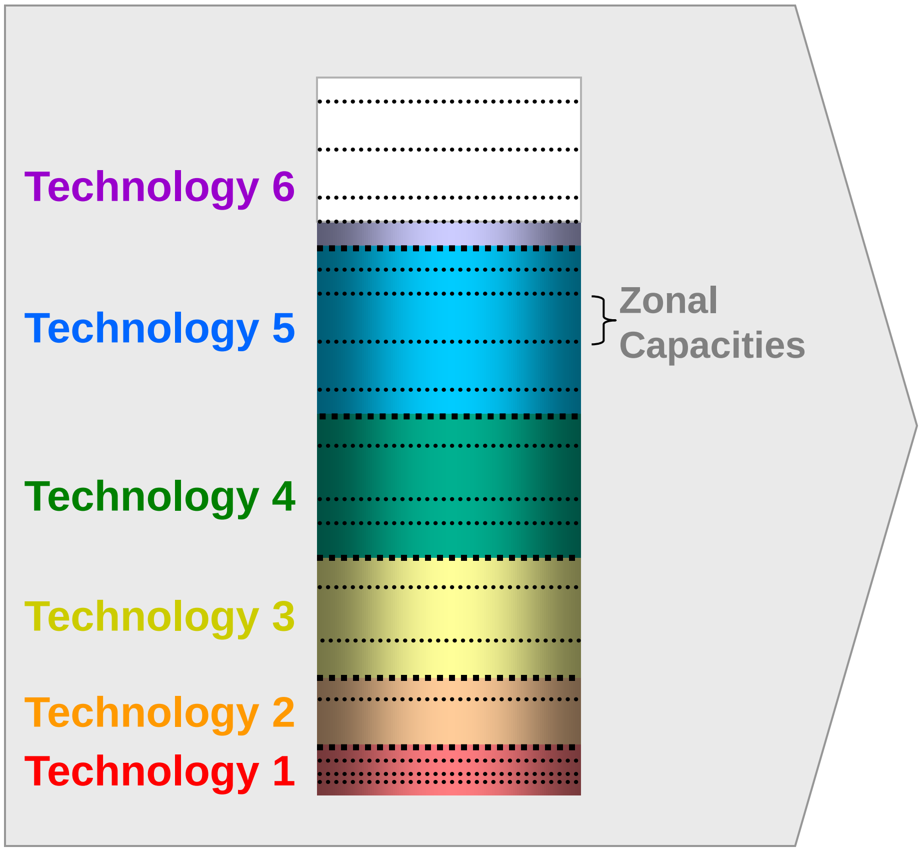
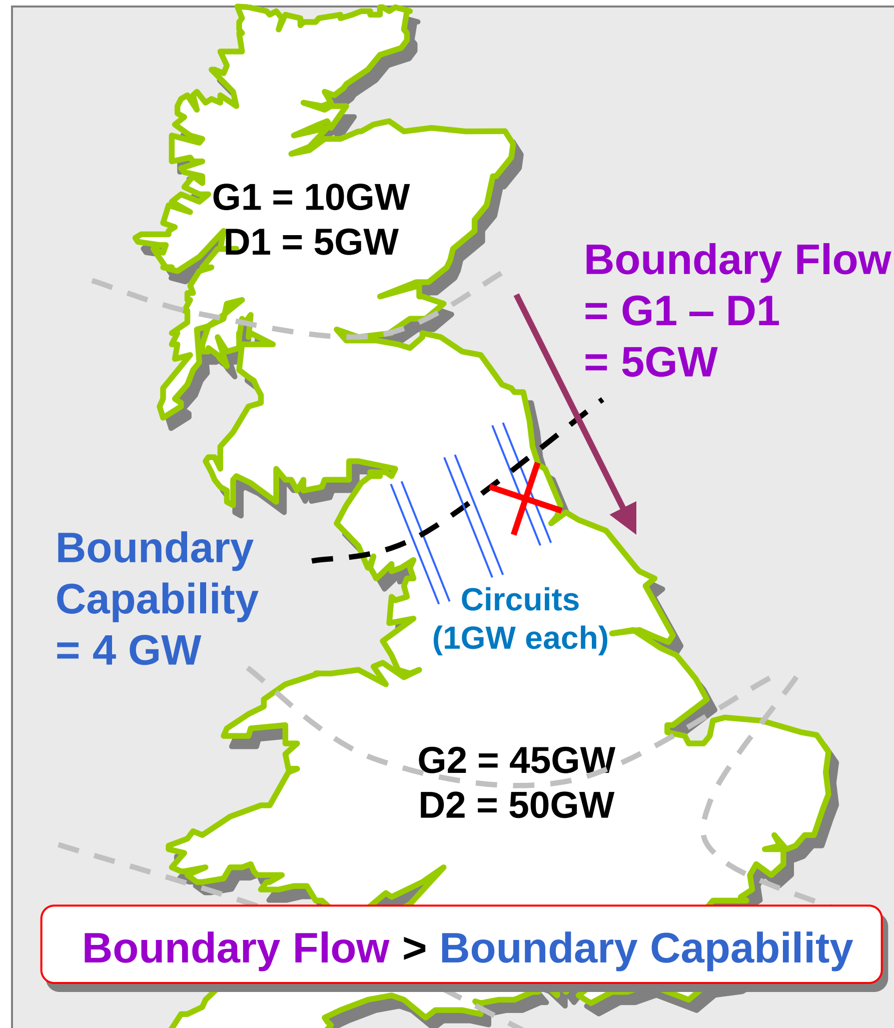
Market Model - Network Capability

Unconstrained Dispatch

(One Demand Sample)

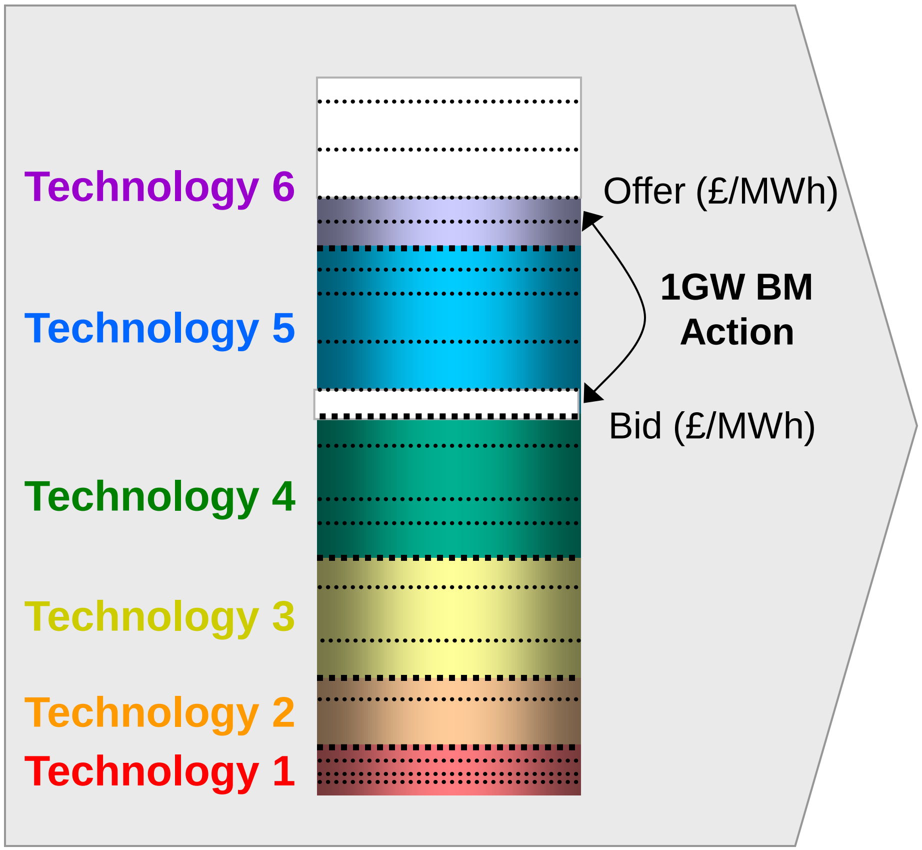


Zonal Network Representation

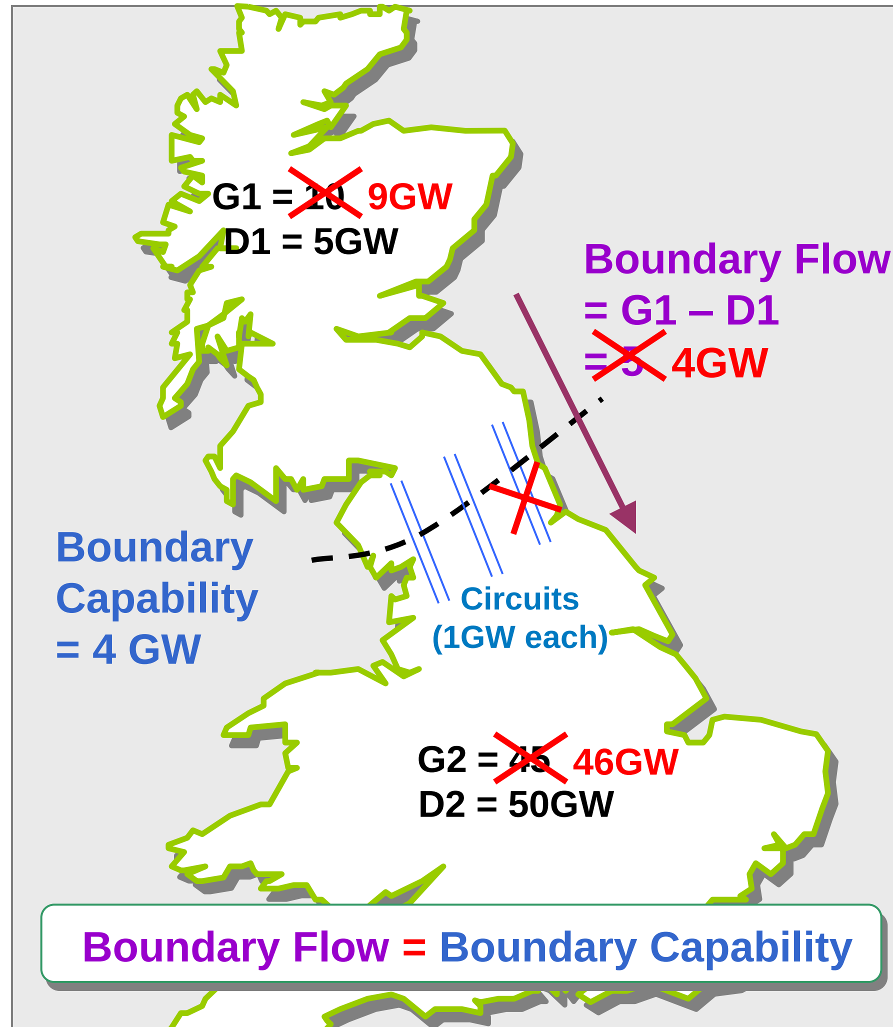


Market Model - Constrained Dispatch

Constrained Dispatch



Zonal Network Representation



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Elements Influencing Constraint Costs

Unconstrained Dispatch

Prices
- Fuel Price
- CO_2 Price
- ROC/FiT Price

Gen Unit
- Installed Cap.
- Unit Avail.
- Fuel Avail.
- Efficiency

Market
- Demand
- Merit Order

+

Constrained Dispatch

Network
- Capability
- Seasonal Avail.
- Outage Avail.
- Investment

BM
- Bid Price
- Offer Price

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Electricity Scenario Illustrator (ELSI)

Developed for RIIO-T1 stakeholder engagement

- Constrained and unconstrained dispatch of generation to meet demand for a number of demand samples in a year
- Zonal network representation
- User sets the background assumptions:
  - Generation capacities, availability, fuel and CO_2 costs, subsidy levels, etc.
  - Boundary capability, boundary reinforcements
  - Demand levels
- ELSI optimises most economic dispatch resulting in:
  - Market/zonal prices
  - Generation running hours, profits and CO_2 emissions
  - Constraint cost and volume information

some limitations arising from simplicity

ELSI – How Does it Work?

Demand

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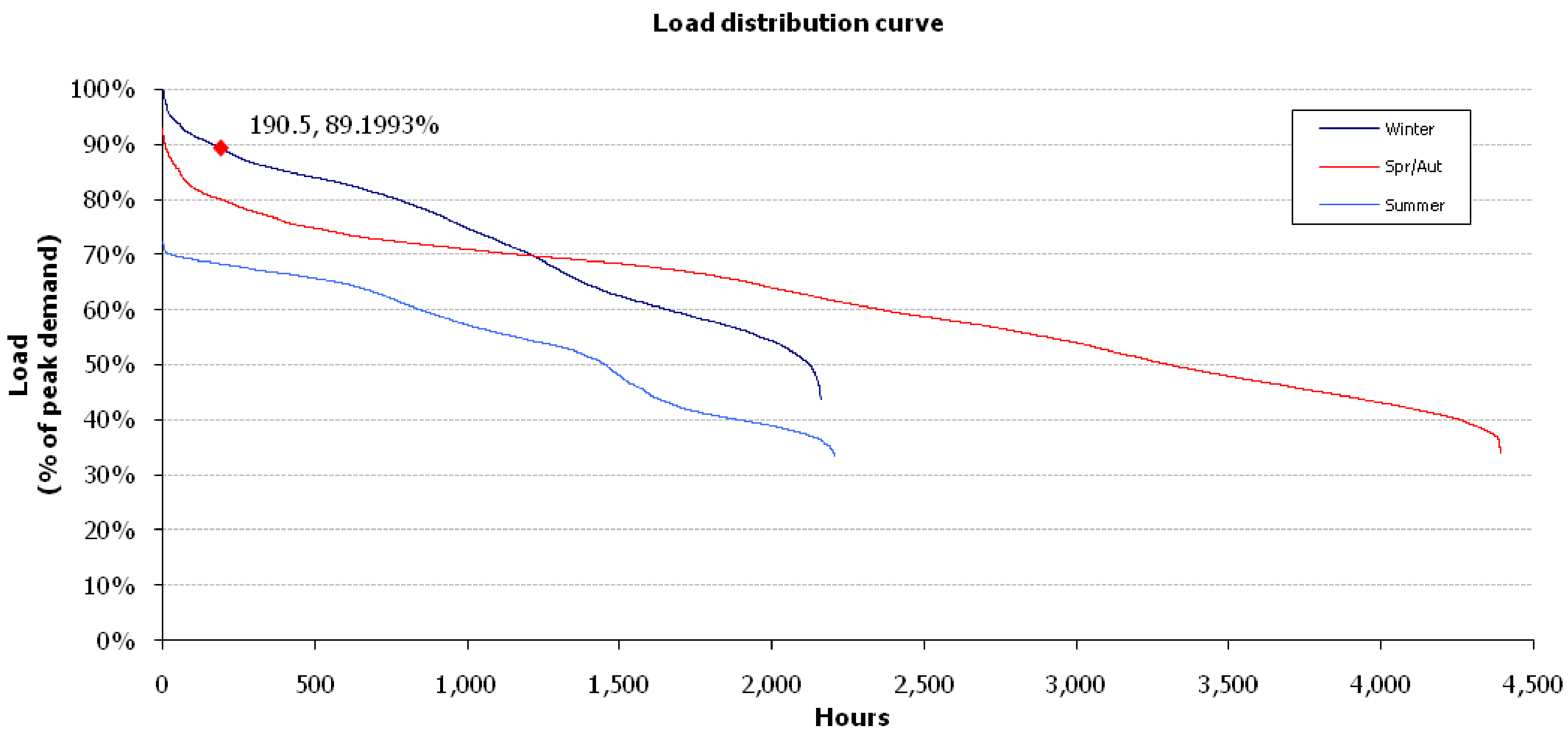
Model Inputs – Demand Samples

- 104 distinct demand samples to represent a year
- Seasonal load durations created using least squares fit of 2 years historic data



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Model Inputs – Demand Samples

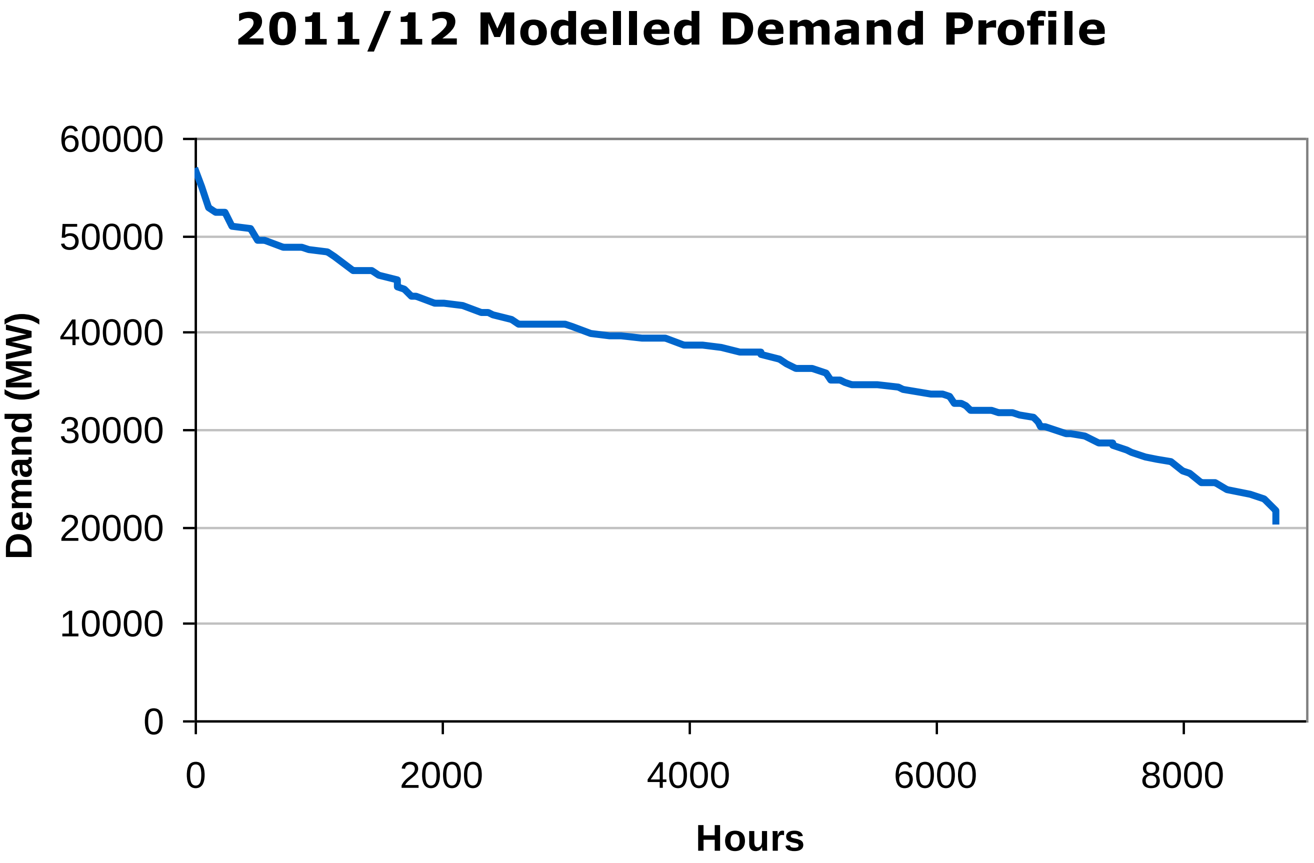
- Recreates both annual and daily demand profiles
- 24 + 1 peak + 1 min day = 26 days to represent a year

Season	Days			Hours				
	Days	Modelled	Days/ Modelled	P1 (peak)	P2 (plateau)	P3 (pickup/ drop off)	P4 (night trough)	Total
Winter	91	6	15.2	3.5	10	3	7.5	24
Spr/Aut	181	12	15.1	4	10	3	7	24
Summer	91	6	15.2	10.5	4	3	6.5	24
Total	363	24						

+ 1 peak and 1 min
= 365 days modelled as 26 in total

- GB wide demand distributed across zonal representation of transmission network

Model Inputs – Demand Samples



- GB wide demand distributed across zonal representation of transmission network

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Model Inputs – Demand Samples

- Zonal distribution of demand for any given sample is based on historic distribution at peak

Zone	Name	IIR	PL	Demand	Zdist
A	London	88	9,734	9,822	17.0%
B	S Coast	42	4,169	4,211	7.3%
C	Estuary	65	1,939	2,004	3.5%
D	S Central	89	2,122	2,211	3.8%
E	SW	23	1,569	1,592	2.8%
F	SW Peninsula	6	1,008	1,014	1.8%
G	W Central	38	2,070	2,108	3.6%
H	South Wales	22	1,982	2,004	3.5%
J	East Mids	150	3,968	4,118	7.1%
K	Trent	135	568	703	1.2%
L	West Mids	151	6,443	6,594	11.4%
M	North Wales	24	676	700	1.2%
N	NW	62	5,115	5,177	9.0%
P	Yorks	122	5,664	5,786	10.0%
Q	North East	51	2,691	2,742	4.7%
R	Cumbria	54	769	823	1.4%
S	S Scot (SPTL)	104	3,950	4,054	7.0%
T	N Scot (SHETL)	100	1,536	1,636	2.8%
U	Norwich, Sizewell & Bramford	0	0	0	0.0%
V	Wylfa & Dinorwig	7	513	520	0.9%
				57,819	

This distribution can be altered in the *Input_Network* worksheet

ELSI – How Does it Work?

Generation

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Model Inputs – Generator Capacity (TEC)

Fuel Type

Zone

TEC

Station	Fuel Type	Availability Grouping Fuel Group	Flop Zone	Flop Major Zone	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
A_CCGT	CCGT	Gas	A	A	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123	2,123
A_OCGT	OCGT	OCGT		A	249	249	249	249	144	144	144	144	144	144	144	144	144	144	144
A_Oil	Oil	Oil		A	1,140	1,140	1,140	1,140	0	0	0	0	0	0	0	0	0	0	0
B_CCGT	CCGT	Gas	B	B	420	420	420	420	420	420	420	420	420	420	420	420	420	420	420
B_CCGT New	CCGT New	Gas		B	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
B_CHP	CHP	Gas		B	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158
B_Intercon Europe Exp	Intercon Europe Ex	IC		B								1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
B_OCGT	OCGT	OCGT		B	179	179	179	179	145	145	145	145	145	145	145	145	145	145	145
B_Offshore Wind	Offshore Wind	Wind		B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
B_Oil	Oil	Oil		B	1,002	1,002	1,002	1,002	0	0	0	0	0	0	0	0	0	0	0
C_CCGT	CCGT	Gas	C	C	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305	2,305
C_CCGT CCS	CCGT CCS	Gas		C	0	0	0	0	0	0	0	0	0	0	0	0	1,800	2,293	4,788
C_CCGT New	CCGT New	Gas		C	1,290	1,250	1,250	1,290	1,290	2,276	2,276	2,276	2,276	2,276	2,276	2,276	2,276	1,783	1,290
C_Coal - LCPD Out	Coal - LCPD Out	Coal		C	2,995	2,995	368	0	0	0	0	0	0	0	0	0	0	0	0
C_Intercon Europe Exp	Intercon Europe Ex	IC		C	3,188	3,188	3,188	3,188	3,188	3,188	3,188	3,188	4,188	4,188	4,188	4,188	4,188	4,188	4,188
C_Nuclear	Nuclear	Nuclear		C	1,081	1,081	1,081	1,081	1,081	1,081	1,081	1,081	1,081	1,081	1,081	1,081	0	0	0
C_OCGT	OCGT	OCGT		C	157	157	123	55	0	0	0	0	0	0	0	0	0	0	0
C_Offshore Wind	Offshore Wind	Wind		C	464	590	1,094	1,094	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
C_Oil	Oil	Oil		C	1,300	1,300	1,300	1,300	0	0	0	0	0	0	0	0	0	0	0
D_CCGT	CCGT	Gas	D	D	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550	1,550
D_Coal - LCPD Out	Coal - LCPD Out	Coal		D	1,458	1,458	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	OCGT	OCGT		D	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	Nuclear	Nuclear	E	E	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	0	0	0	0	0
[illegible]	Nuclear New	Nuclear New		E	0	0	0	0	0	0	0	0	1,670	1,670	1,670	1,670	3,340	3,340	3,340
[illegible]	Offshore Wind	Wind		E	0	0	0	0	0	0	0	0	0	0	0	0	0	0	300
[illegible]	Wave & Tidal	Wave & Tidal		E	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[illegible]	CCGT New	Gas	F	F	905	905	905	905	905	905	905	905	905	905	905	905	905	905	905
[illegible]	OCGT	OCGT		F	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
[illegible]	Offshore Wind	Wind		F	0	0	0	0	0	0	0	302	708	1,110	1,110	1,110	1,110	1,110	1,110
[illegible]	Wave & Tidal	Wave & Tidal		F								25	50	75	100	125	150	175	200
[illegible]	Biomass	Biomass	G	G	0	0	0	0	0	0	0	0	0	0	0	165	165	165	165
[illegible]	CCGT	Gas		G	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234	1,234
[illegible]	Nuclear	Nuclear		G	215	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_Biomass	Biomass	Biomass	H	H	0	0	0	0	350	350	350	350	350	350	350	350	350	350	350
H_CCGT	CCGT	Gas		H	522	522	787	787	787	522	522	522	522	522	522	522	522	522	522
H_CCGT New	CCGT New	Gas		H	1,690	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950
H_Coal - LCPD In	Coal - LCPD In	Coal		H	1,932	1,932	1,932	1,932	1,932	1,932	1,932	1,932	363	363	363	383	0	0	0
H_OCGT	OCGT	OCGT		H	81	81	81	81	81	81	81	81	30	30	30	30	30	30	30
J_CCGT	CCGT	Gas	J	J	1,885	1,885	2,830	2,830	2,830	1,885	1,885	1,885	1,484	819	819	819	819	819	819
J_CCGT New	CCGT New	Gas		J					981	981	981	981	981	981	981	981	981	981	981
J_Offshore Wind	Offshore Wind	Wind		J	0	250	250	500	750	750	750	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
K_CCGT	CCGT	Gas	K	K	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275	1,275
K_CCGT New	CCGT New	Gas		K	2,135	3,005	3,005	3,005	3,005	3,005	3,005	3,005	3,845	3,845	3,845	3,845	3,845	3,845	3,845
K_Clean Coal CCS	Clean Coal CCS	Coal		K	0	0	0	0	0	0	0	0	0	0	0	0	2,000	2,000	2,000
K_Coal - LCPD In	Coal - LCPD In	Coal		K	3,947	3,947	3,947	3,947	3,947	3,947	3,947	3,947	3,947	2,000	2,000	2,000	0	0	0
K_OCGT	OCGT	OCGT		K	40	40	40	40	40	40	40	40	40	0	0	0	0	0	0
K_Offshore Wind	Offshore Wind	Wind		K	0	0	0	0	0	0	0	400	800	1,200	1,200	1,200	1,200	1,200	1,200
L_CCGT New	CCGT New	Gas	L	L	0	0	0	0	0	0	0	1,320	1,320	1,320	1,320	1,320	1,320	1,320	1,320
L_CHP	CHP	Gas		L	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218
L_Coal - LCPD In	Coal - LCPD In	Coal		L	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	2,955	968	968	968	0	0	0
L_Coal - LCPD Out	Coal - LCPD Out	Coal		L	964	964	0	0	0	0	0	0	0	0	0	0	0	0	0
L_OCGT	OCGT	OCGT		L	84	84	84	84	84	84	84	84	84	50	50	50	0	0	0
L_Onshore Wind	Onshore Wind	Wind		L	0	0	0	0	176	659	659	659	659	659	659	659	659	659	659
M_CCGT	CCGT	Gas	M	M	1,895	1,835	1,835	1,895	1,895	1,895	1,835	1,380	1,380	1,380	1,380	1,380	1,380	1,380	1,380
M_CHP	CHP	Gas		M	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
M_Intercon Ireland Exp	Intercon Ireland Ex	IC		M	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500
M_Pumped Storage Gw	Pumped Storage [illegible]	[illegible]		[illegible]	[illegible]	380	360	360	380	[illegible]	[illegible]	[illegible]	360	380	360	380	380	380	380
N_CCGT	CCGT	[illegible]		[illegible]	[illegible]	810	810	810	810	[illegible]	[illegible]	[illegible]	810	810	810	810	810	810	810
N_CCGT New	CCGT New	[illegible]		[illegible]	[illegible]			910	910	[illegible]	[illegible]	[illegible]	910	2,430	2,430	2,430	2,430	2,430	2,430
N_Coal - LCPD In	Coal - LCPD In	[illegible]		[illegible]	[illegible]	1,953	1,953	1,953	1,953	[illegible]	[illegible]	[illegible]	1,953	1,953	1,953	1,953	0	0	0
N_OCGT	OCGT	[illegible]		[illegible]	[illegible]	34	34	34	34	[illegible]	[illegible]	[illegible]	34	34	34	34	0	0	0
P_Biomass	Biomass	[illegible]		[illegible]	[illegible]	0	0	250	290	[illegible]	[illegible]	[illegible]	580	580	580	580	580	580	580
P_CCGT	CCGT	[illegible]		[illegible]	[illegible]	4,880	4,920	4,920	4,920	[illegible]	[illegible]	[illegible]	4,880	3,095	3,095	3,095	3,095	3,095	1,100
P_CCGT CCS	CCGT CCS	Gas		P	0	0	0	0	0	0	0	0	0	0	0	0	0	2,000	2,000
P_CHP	CHP	Gas		P	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Calc MultiYear | Results Annual | Wk Load duration | Wk Wind data | Wk Random numbers | Input Network | Input AG Updated | Input SP Updated | Input GG June Updated | Gen Avail Random num

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Model Inputs – Generator Availability of TEC

- Representing planned and unplanned outages

Fuel Type	Fuel grouping	W_avail	SA_avail	S_Avail
Hydro	Renewables	75%	50%	25%
Offshore Wind	Renewables	100%	100%	100%
Onshore Wind	Renewables	100%	100%	100%
Wave & Tidal	Renewables	100%	100%	100%
Nuclear	Nuclear	70%	60%	50%
Nuclear New	Nuclear	80%	75%	70%
Biomass	Renewables	80%	75%	70%
CHP	Gas	80%	75%	70%
CHP New	Gas	80%	75%	70%
CCGT CCS	Gas	80%	75%	70%
Clean Coal CCS	Coal	80%	75%	70%
CCGT New	Gas	80%	75%	70%
Gas - Other	Gas	80%	75%	70%
CCGT	Gas	80%	75%	70%
Intercon Europe Imp	Intercon Europe	95%	95%	95%
Intercon Europe Float	Intercon Europe	95%	95%	95%
Intercon Europe Exp	Intercon Europe	95%	95%	95%
Coal - LCPD In	Coal	80%	75%	70%
Coal - LCPD Out	Coal	80%	75%	70%
Coal - Non LCPD	Coal	80%	75%	70%
Intercon Ireland Imp	Intercon Ireland	95%	95%	95%
Intercon Ireland Float	Intercon Ireland	95%	95%	95%
Intercon Ireland Exp	Intercon Ireland	95%	95%	95%
Pumped Storage Pump	Pumped Storage	95%	80%	70%
Pumped Storage Gen	Pumped Storage	95%	80%	70%
Pumped Storage Float	Pumped Storage	95%	80%	70%
Oil	Peaking	90%	80%	70%
OCGT	Peaking	100%	100%	100%
User defined	User defined	100%	100%	100%
Curtail	Curtail	100%	100%	100%

- How many MW are available in a given period out of the total installed MW?
- Seasonal straight scale
- Wind and wave modelled probabilistically using historic data (10 years)
- Pumped Storage optimised in order to minimise daily short-run costs

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Model Inputs – Generator Availability of TEC

- Alternative approach being developed using probabilistic distributions and random numbers – *similar to wind*

	Grouping		Mean			St. Dev.		
Fuel Type	Availability Fuel	Outage Modelling	Group_W_avail	Group_SA_avail	Group_S_Avail	Group_W_st_dev	Group_SA_st_dev	Group_S_st_dev
Hydro	Hydro	0	75%	50%	25%	0%	0%	0%
Offshore Wind	Wind	0	100%	100%	100%	0%	0%	0%
Onshore Wind	Wind	0	100%	100%	100%	0%	0%	0%
Wave & Tidal	Wave & Tidal	0	100%	100%	100%	0%	0%	0%
Nuclear	Nuclear	1	83%	75%	73%	8%	12%	11%
Nuclear New	Nuclear New	1	83%	75%	73%	8%	12%	11%
Biomass	Biomass	1	83%	75%	73%	7%	6%	5%
CHP	Gas	1	83%	75%	73%	7%	6%	5%
CHP New	Gas	1	83%	75%	73%	7%	6%	5%
CCGT CCS	Gas	1	83%	75%	73%	7%	6%	5%
Clean Coal CCS	Coal	1	83%	70%	56%	6%	11%	6%
CCGT New	Gas	1	83%	75%	73%	7%	6%	5%
Gas - Other	Gas	1	83%	75%	73%	7%	6%	5%
CCGT	Gas	1	83%	75%	73%	7%	6%	5%
Intercon Europe Imp	IC	0	95%	95%	95%	0%	0%	0%
Intercon Europe Float	IC	0	95%	95%	95%	0%	0%	0%
Intercon Europe Exp	IC	0	95%	95%	95%	0%	0%	0%
Coal - LCPD In	Coal	1	83%	70%	56%	6%	11%	6%
Coal - LCPD Out	Coal	1	83%	70%	56%	6%	11%	6%
Coal - Non LCPD	Coal	1	83%	70%	56%	6%	11%	6%
Intercon Ireland Imp	IC	0	95%	95%	95%	0%	0%	0%
Intercon Ireland Float	IC	0	95%	95%	95%	0%	0%	0%
Intercon Ireland Exp	IC	0	95%	95%	95%	0%	0%	0%
Pumped Storage Pump	PS	0	95%	80%	70%	0%	0%	0%
Pumped Storage Gen	PS	0	95%	80%	70%	0%	0%	0%
Pumped Storage Float	PS	0	95%	80%	70%	0%	0%	0%
Oil	Oil	1	90%	80%	70%	6%	11%	6%
OCGT	OCGT	1	91%	86%	85%	8%	10%	9%
User defined	User defined	0	100%	100%	100%	0%	0%	0%
Curtail	Curtail	0	100%	100%	100%	0%	0%	0%

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Model Inputs – Generation Merit Order

Results | Workings | Inputs | All

Gone Green (GG) scenario. Generation & Demand

May update by modded to include small Scottish embedded wind generation

Basic cost assumptions

		£/MWh @ 100% eff	
Gas p/th	58	19.80	Uses 1 therm = 29.3 kWh
Coal £/t	75	11.19	Assumes 1 t coal = 24GJ = 6.7MWh
Oil £/barrel	62.5	39.00	Assumes 7.3 barrels per toe and 1 toe = 42GJ = 11.7 MWh
Distillate £/t	560	44.80	Assume 1 t = 45GJ = 12.5MWh
VLL £/MWh	4000		
CO2 £/t	26		

Conversion efficiencies

CCGT	55%
CCGT New	58%
CCGT CCS	50%
Coal	35%
Coal CCS	30%
Oil	35%
OCGT	30%
CHP	90%
Pump_storage_eff	70%
Intercon_loss	2.5%

CO2 emissions

	g/MJ	t CO2/MWh @ 100% eff		t CO2/MWh (e)
gas	55	0.198	CCGT	0.360
coal	90	0.324	Coal	0.926
oil	70	0.252	Oil	0.720

Prices & Availabilities

ROC £50

Fuel Type	Fuel grouping	V_avail	SA_avail	S_Avail	CO2 t/MWh	CO2 £/MWh	Fuel	SRMC	Bid (0.6)	Offer (1.6)	
Hydro	Renewables	75%	50%	25%	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00	
Offshore Wind	Renewables	100%	100%	100%	0.00	£0.00	£0.01	£0.01	-£100.00	£0.00	
Onshore Wind	Renewables	100%	100%	100%	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00	
Wave & Tidal	Renewables	100%	100%	100%	[illegible]	[illegible]	£0.01	£0.01	-£50.00	£0.00	
Nuclear	Nuclear	70%	60%	50%	[illegible]	[illegible]	£6.50	£6.50	£0.00	£10.40	
Nuclear New	Nuclear	80%	75%	70%	[illegible]	[illegible]	£6.50	£6.50	£0.00	£10.40	
Biomass	Renewables	80%	75%	70%	[illegible]	[illegible]	£25.00	£25.00	£15.00	£40.00	
CHP	Gas	80%	75%	70%	[illegible]	[illegible]	£21.99	£27.71	£16.63	£44.34	
CHP New	Gas	80%	75%	70%	0.22	£5.72	£21.99	£27.71	£16.63	£44.34	
CCGT CCS	Gas	80%	75%	70%	0.00	£0.00	£39.99	£39.99	£23.99	£63.98	
Clean Coal CCS	Coal	80%	75%	70%	0.00	£0.00	£37.63	£37.63	£22.58	£60.20	
CCGT New	Gas	80%	75%	70%	0.34	£8.88	£34.13	£43.01	£25.80	£68.81	
Gas - Other	Gas	80%	75%	70%	0.34	£8.88	£34.13	£43.01	£25.80	£68.81	
CCGT	Gas	80%	75%	70%	0.36	£9.36	£35.99	£45.35	£27.21	£72.56	
Intercon Europe Imp	Intercon Europe	95%	95%	95%	0.00			£0.00	£0.00	£0.00	
Intercon Europe Float	Intercon Europe	95%	95%	95%	0.00	£9.36	£35.99	£44.22	£26.53	£70.75	
Intercon Europe Exp	Intercon Europe	95%	95%	95%	0.00	£9.36	£35.99	£46.49	£27.89	£74.38	
Coal - LCPD In	Coal	80%	75%	70%	0.93	£24.07	£31.98	£56.05	£33.63	£89.68	
Coal - LCPD Out	Coal	80%	75%	70%	0.93	£24.07	£31.98	£56.05	£33.63	£89.68	
Coal - Non LCPD	Coal	80%	75%	70%	0.93	£24.07	£31.98	£56.05	£33.63	£89.68	
Intercon Ireland Imp	Intercon Ireland	95%	95%	95%	0.00			£0.00	£0.00	£0.00	
Intercon Ireland Float	Intercon Ireland	[illegible]	[illegible]	[illegible]	0.00	£24.07	£31.98	£54.65	£32.79	£87.44	
Intercon Ireland Exp	Intercon Ireland	[illegible]	[illegible]	[illegible]	0.00	£24.07	£31.98	£57.45	£34.47	£91.92	
Pumped Storage Pump	Pumped Storage	[illegible]	[illegible]	[illegible]	0.00			£0.00	£0.00	£0.00	NB These pri
Pumped Storage Gen	Pumped Storage	[illegible]	[illegible]	[illegible]	0.00			£56.61	£33.97	£90.58	NB These pri
Pumped Storage Float	Pumped Storage	[illegible]	[illegible]	[illegible]	0.00			£39.63	£23.78	£63.41	NB These pri
Oil	Peaking	90%	80%	70%	0.72	£18.72	£111.42	£130.14	£78.08	£208.22	
OCGT	Peaking	100%	100%	100%	0.84	£21.84	£149.33	£171.17	£102.70	£273.88	
User defined	User defined	100%	100%	100%	0.84	£21.84	£149.33	£171.17	£102.70	£273.88	
Curtail	Curtail	100%	100%	100%	0.00			£4,000.00	£4,000.00	£4,000.00	

Input AG / Input AG Updated / Input GG / Input GG Updated / **Input GG June Updated** / Input SP / Input SP Upda

Fuel Type

CO_2

Avail

Cost

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ELSI – How Does it Work?

Network

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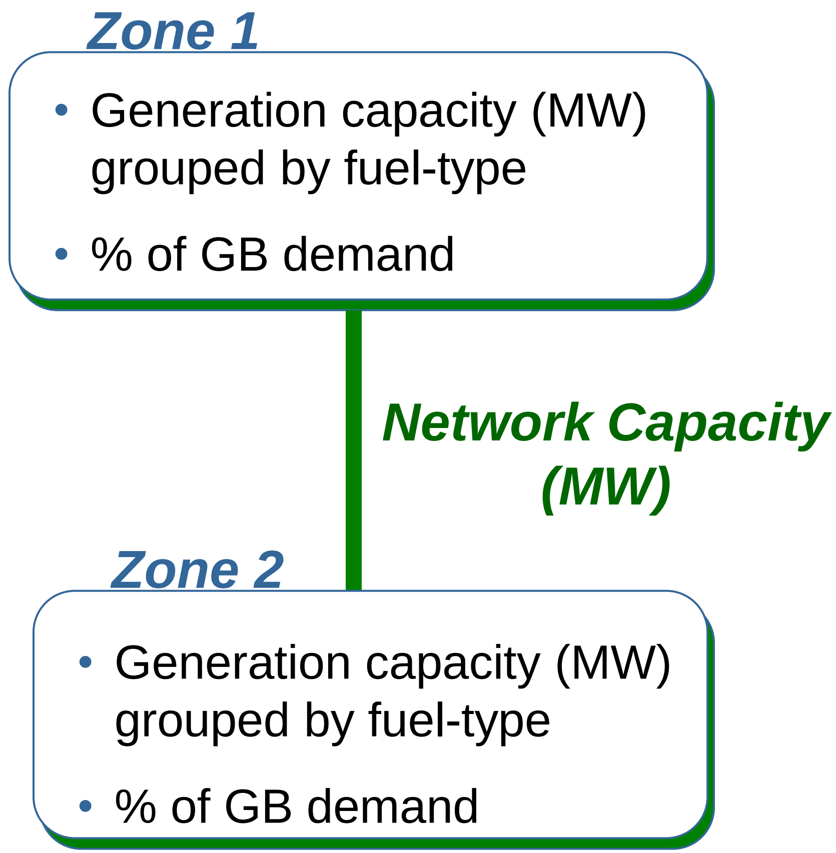
Transmission Network Modelling

- Zonal network model



- Defined within the *Input_Network* worksheet

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Transmission Network Modelling

Zonal Interconnectivity

			Constraint												
			North to South	Scotland to Engl	Upper North	North-Mids	dlands to So	SW & South	NE & Yorks	st, South Coast & Sc	SW	London	hames Estua	E Trent& Yor	West Mids
Zone	Name	Transfer MW	B4	B6	B7a	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17
A	London									1		-1			
B	S Coast							-1							
C	Estuary									1			1		
D	S Central														
E	SW							-1			1				
F	SW Peninsula							-1			1				
G	W Central														
H	South Wales														
J	East Mids									1					
K	Trent						1			1				1	
L	West Mids						1			1					-1
M	North Wales					1	1			1					
N	NW					1	1			1					
P	Yorks					1	1		1	1				1	
Q	North East				1	1	1		1	1				1	
R	Cumbria				1	1	1			1					
S	S Scot (SPTL)			1	1	1	1		1	1				1	
T	N Scot (SHETL)		1	1	1	1	1		1	1				1	
U	Norwich, Sizewell & Bramford									1					
V	Wylfa & Dinorwig					1	1			1					
Use of capacity (MW)															

Network Capacity

		Constraint												
		B4	B6	B7a	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17
Base Capabilities (MW)	N-2	2,205	3,300	5,400	11,300	12,600	5,800	9,900	5,800	1,800	9,600	6,400	15,200	5,200
	N-1	3,205	4,221	7,212	13,351	13,800	7,244	10,400	7,509	3,394	10,925	8,759	15,653	7,925
	Selective N-1	*3,205*	*4,221*	*7,212*	11,300	12,600	5,800	9,900	5,800	1,800	9,600	6,400	15,200	5,200
Using N-2	**Winter**	**2,205**	**3,300**	**5,400**	**11,300**	**12,600**	**5,800**	**9,900**	**5,800**	**1,800**	**9,600**	**6,400**	**15,200**	**5,200**
	90% Spr/Aut	1,985	2,970	4,860	10,170	11,340	5,220	8,910	5,220	1,620	8,640	5,760	13,680	4,680
	80% Summer	1,764	2,640	4,320	9,040	10,080	4,640	7,920	4,640	1,440	7,680	5,120	12,160	4,160

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Transmission Network Modelling

Reinforcement Plan

New schemes creating additional capacity

Slow Prog	Gone Green	Accel Growth	User Override	Active	£m	Reinf package	Blank	Constraint B4	B6	B7a	B8	B9	B10	B11	B12	B13	B14	B15	B16	B17
2014	2014	2014	TRUE	FALSE		Beauly-Denny overhead line		950												
2016	2016	2016	TRUE	FALSE		400kV Ring Kintore Reactive Compensation		750												
2016	2016	2016	TRUE	FALSE		Denny-Kincardine 400kV		800												
2018	2015	2015	TRUE	FALSE	710	Western HVDC Link			2,100	2,100										
2014	2014	2014	TRUE	FALSE	80	Anglo-Scottish Series & Shunt Compensation			1,000											
3000	2018	2017	TRUE	FALSE	580	Eastern HVDC Link		2,100	2,100	700										
2014	2014	2014	TRUE	FALSE	40	Penwortham QBs				400										
2021	2019	2019	TRUE	FALSE	450	New Hinckley Point - Seabank OHL and assoc works										3,000				
2016	2016	2014	TRUE	FALSE	90	Reconductoring circuits in East Anglia														
2021	2018	2015	TRUE	FALSE	360	New OHL & reconductoring work in East Anglia														
2023	2020	2018	TRUE	FALSE	40	QBs in East Anglia														
2016	2016	2015	TRUE	FALSE	170	Establish 2nd Pentir-Traw 400kv circuit														
2022	2020	2020	TRUE	FALSE	625	Wylfa-Pembroke HVDC link					2,000	2,000								
2014	2014	2014	TRUE	FALSE	5	B8 Reactive Phase 1					300									
2020	2020	2020	TRUE	FALSE	15	B8 Reactive Phase 2					700									
2015	2015	2015	TRUE	FALSE	220	North London Reinforcements											800			
3000	2021	2021	TRUE	FALSE	210	North East London uprate to 400kV														
3000	2021	2021	TRUE	FALSE	20	East London reinforcements														
3000	2021	2021	TRUE	FALSE	20	East London reconductoring														
3000	2021	2021	TRUE	FALSE	70	South London reconductoring														
3000	2021	2021	TRUE	FALSE	40	New reactor at Rayleigh														
2015	2015	2015	TRUE	FALSE	45	Midlands to South Strategy + B9 reactive						400							1,500	
3000	3000	2022	TRUE	FALSE	130	Pentir - Deeside Reconductoring 400kV Circuit														
3000	3000	2022	TRUE	FALSE	150	Pentir - Trawsfynndd Reconductoring 400kV circuit														
3000	3000	2020	TRUE	FALSE	250	2nd Eastern HVDC Link			2,000	700										
		2011			0	Additional cap (MW)	Winter	0	0	0	0	0	0	0	0	0	0	0	0	0
							Spr/Aut	0	0	0	0	0	0	0	0	0	0	0	0	0
							Summer	0	0	0	0	0	0	0	0	0	0	0	0	0

ELSI – How Does it Work?

Market

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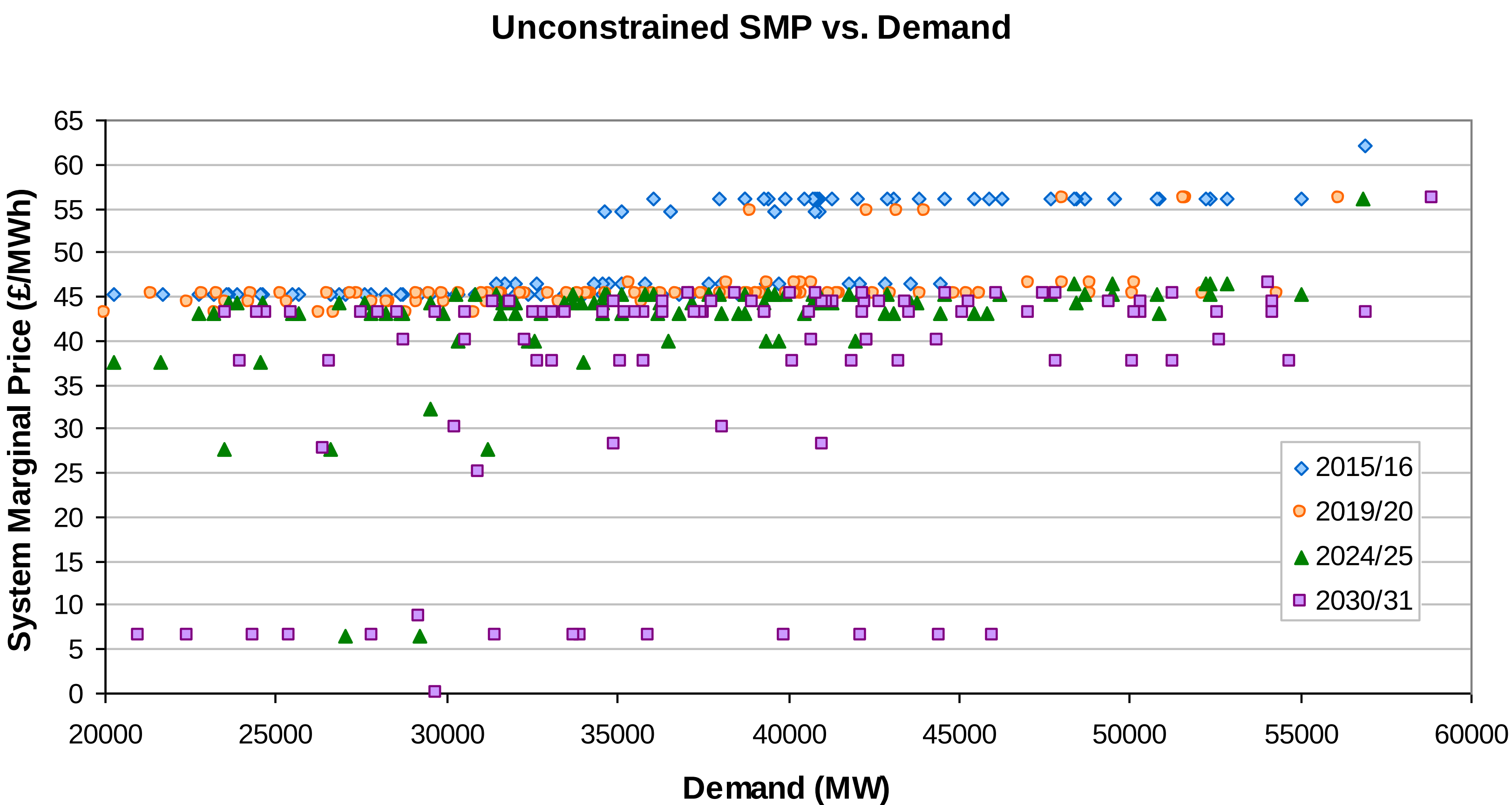
Market Modelling – Generation Despatch

- For each demand sample the optimiser will despatch the cheapest available generation to meet demand based on SRMC and available TEC



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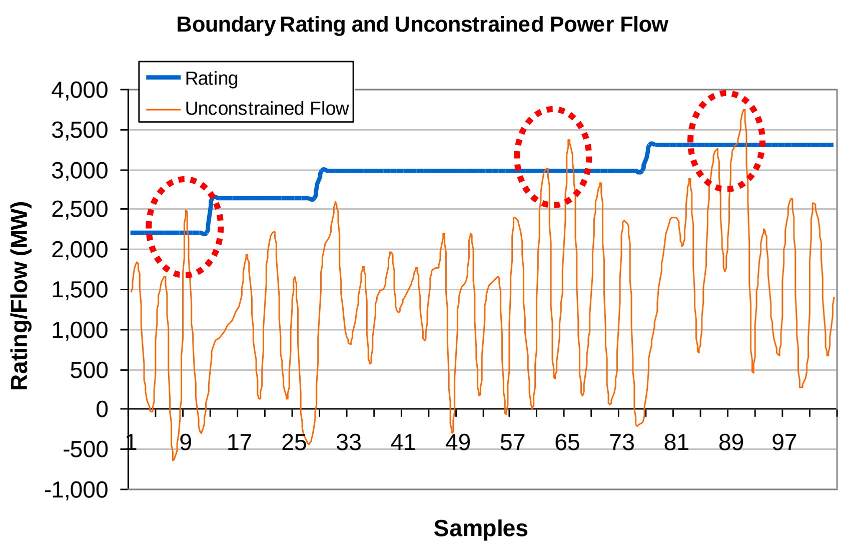
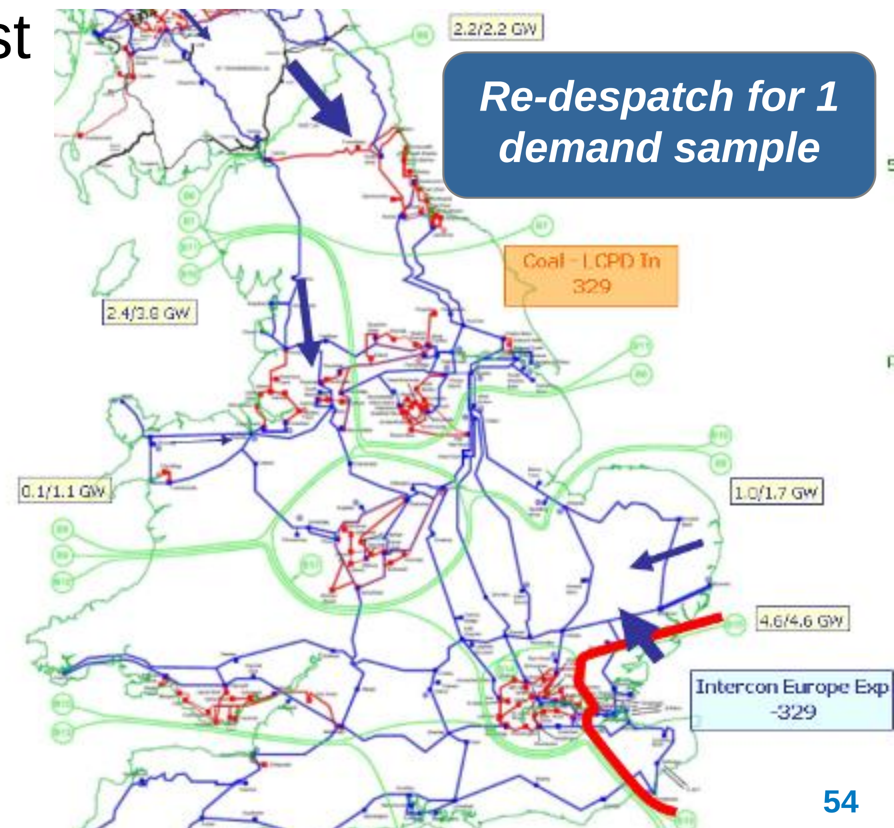
Market Modelling – Generation Re-Despatch

- This economic optimum dispatch will lead to power flows from one zone to another
- At times these flows will exceed the network capacity
- Re-despatch = additional cost = "constraint cost"

2011/12 Annual B6 Boundary Flows





ii CMP213 – Historic Bid Analysis

November 30th 2012

Ivo Spreeuwenberg

Overview

- Historic bid price analysis to ascertain characteristics of generating plant used in planning network capacity
- 2011 daily average bid price and volume

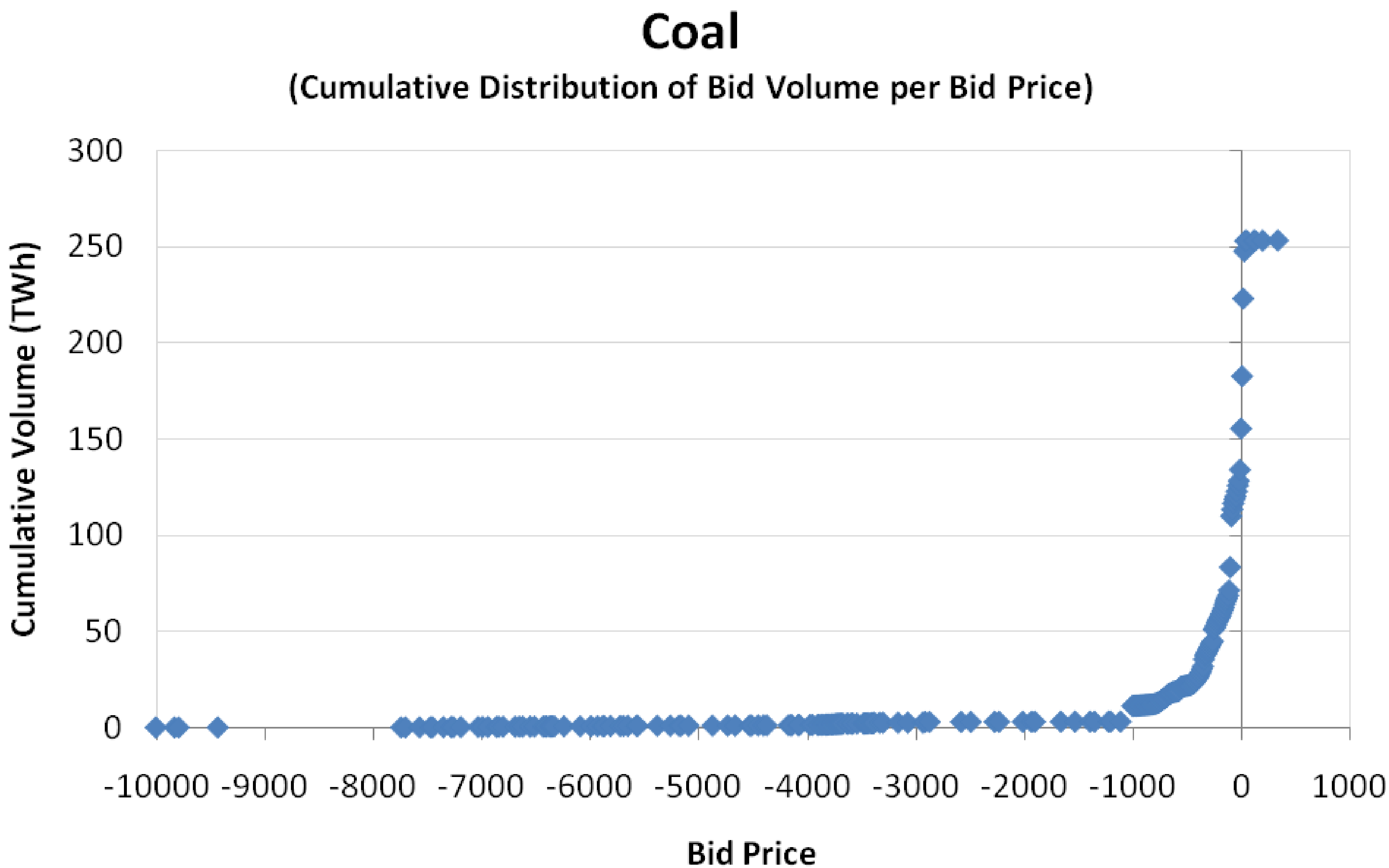
- Long-term network planning would exclude SO related restrictions and some limits to plant technical characteristics

- EMR – capacity payment and FiT considerations

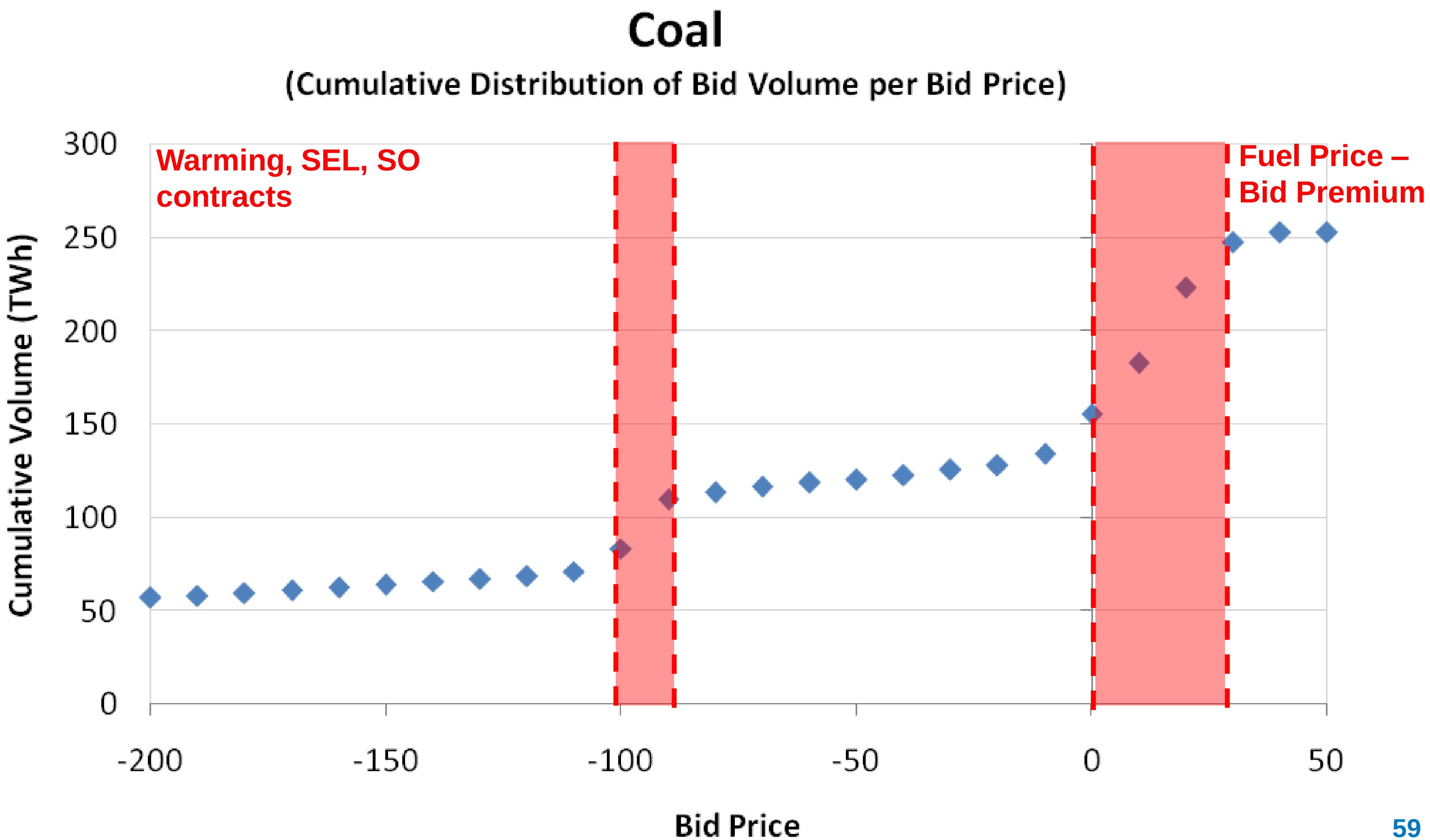
Overview

Fuel Type	Price Point 1 (£/MWh)	Price Point 2 (£/MWh)	Price Point 3 (£/MWh)
Coal	-1,000	-90	0 to 30
Gas	-10,000 to -4,000	-180	0 to 40
OCGT	-100	30 to 50	320
Oil	0	40	-
Hydro	-150	-90 to -50	-10 to 40
Nuclear	-10,000	-	-
Wind	-10,000	-175	-150

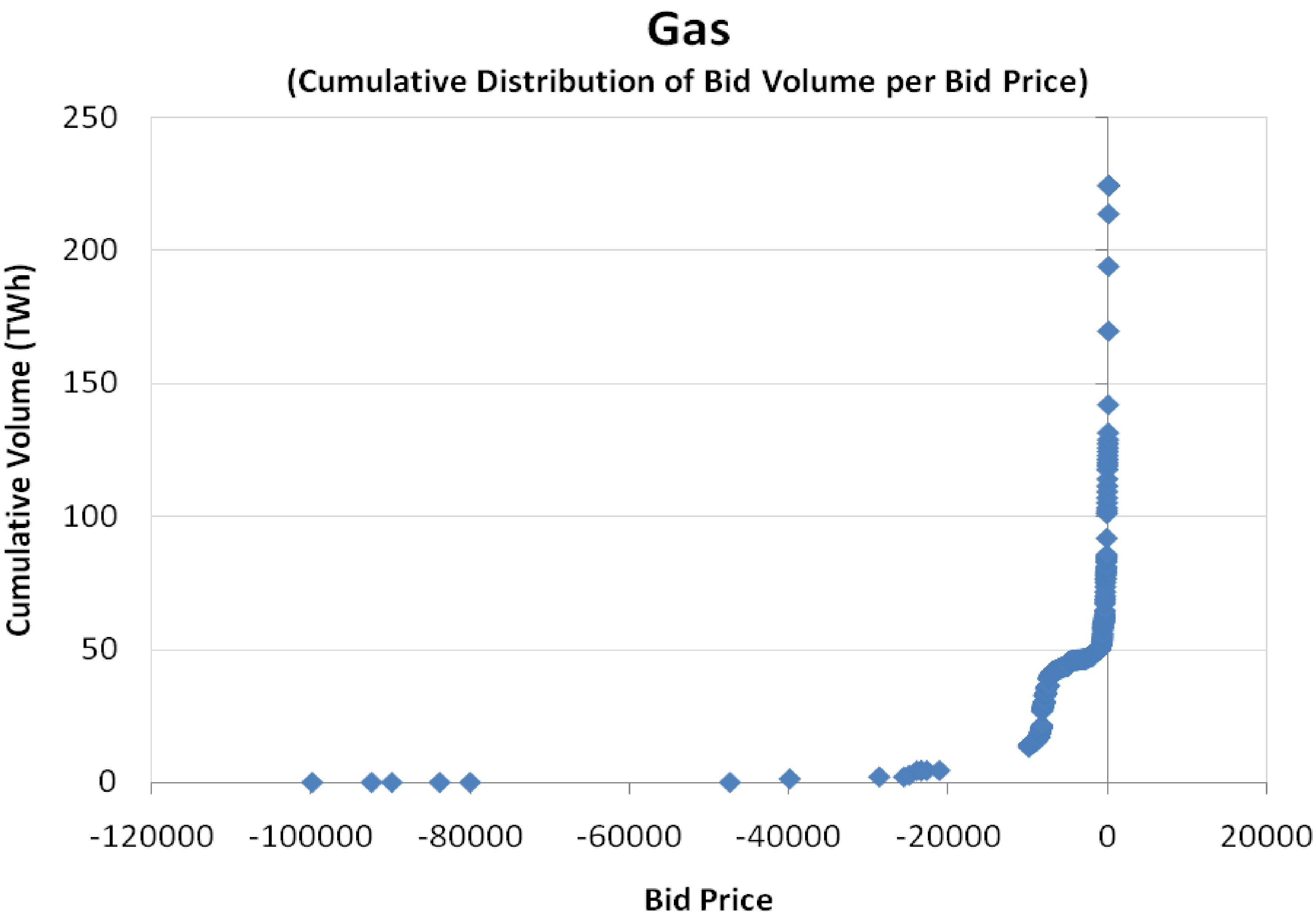
Coal


Coal
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
300
250
200
150
100
50
0
-10000
-9000
-8000
-7000
-6000
-5000
-4000
-3000
-2000
-1000
0
1000
Bid Price

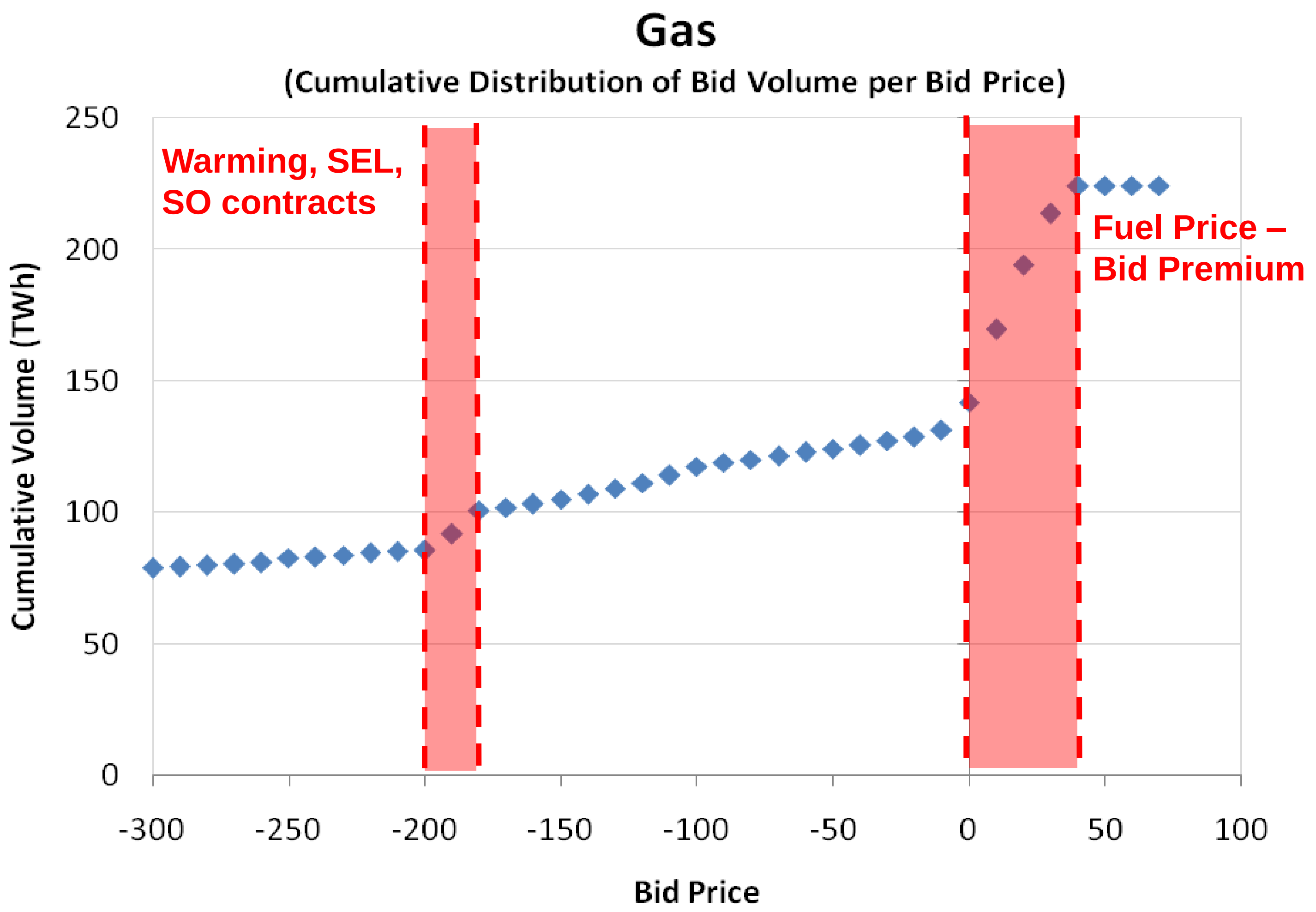
Coal


Coal
(Cumulative Distribution of Bid Volume per Bid Price)
Warming, SEL, SO contracts
Fuel Price – Bid Premium
Cumulative Volume (TWh)
300
250
200
150
100
50
0
-200
-150
-100
-50
0
50
Bid Price

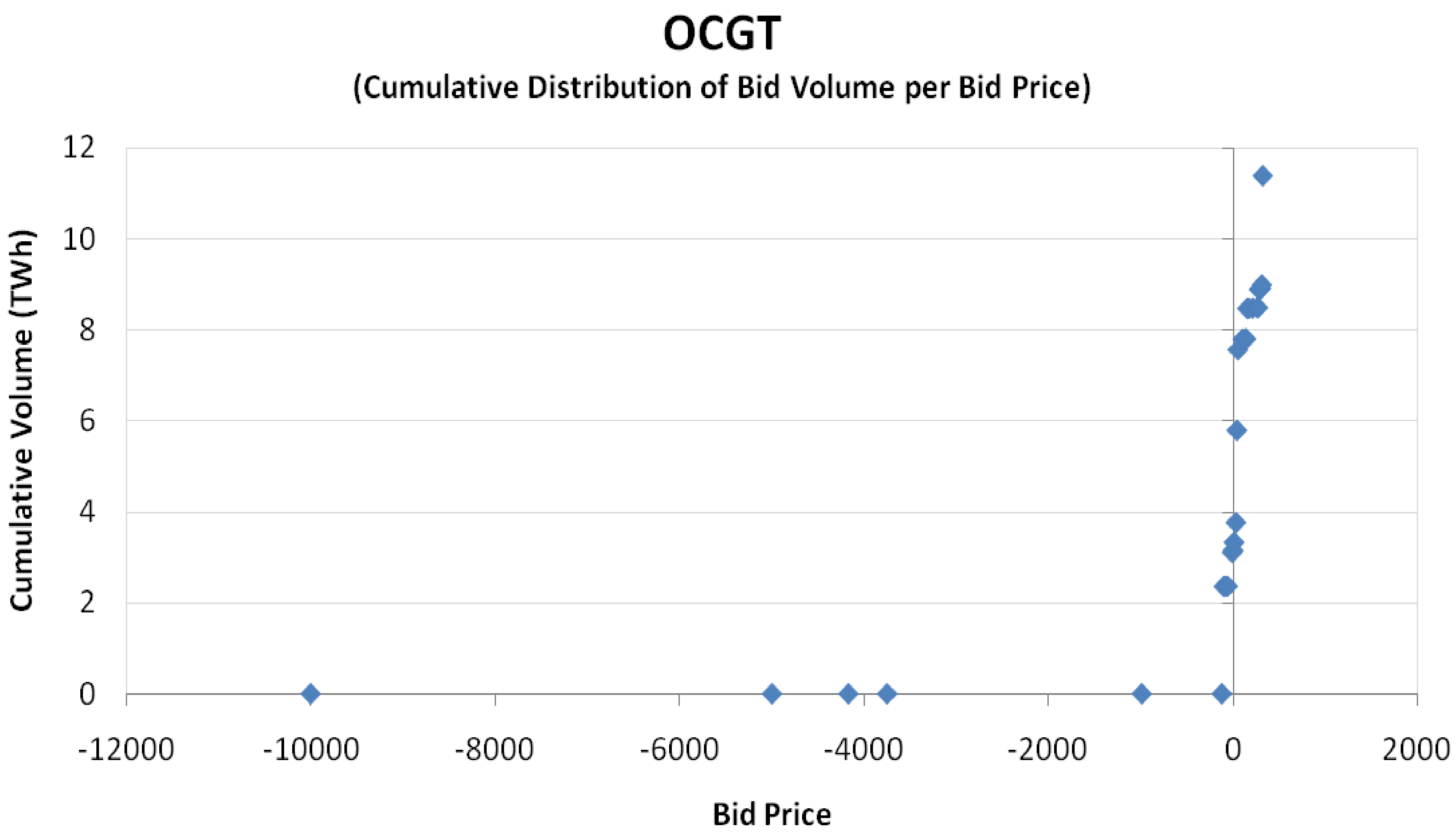
Gas


Gas
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
250
200
150
100
50
0
-120000
-100000
-80000
-60000
-40000
-20000
0
20000
Bid Price

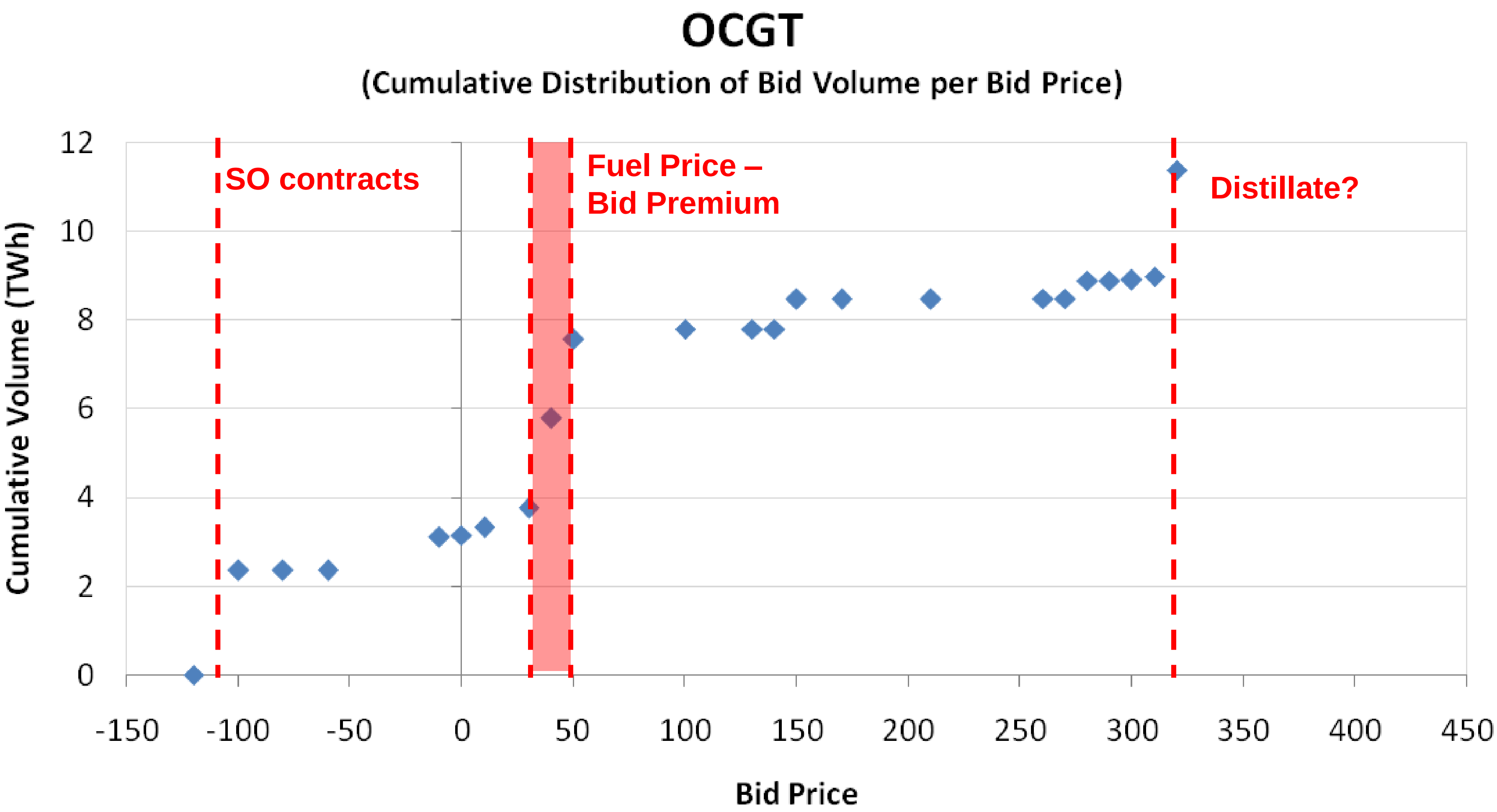
Gas


Gas
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
250
200
150
100
50
0
-300
-250
-200
-150
-100
-50
0
50
100
Bid Price
Warming, SEL, SO contracts
Fuel Price – Bid Premium

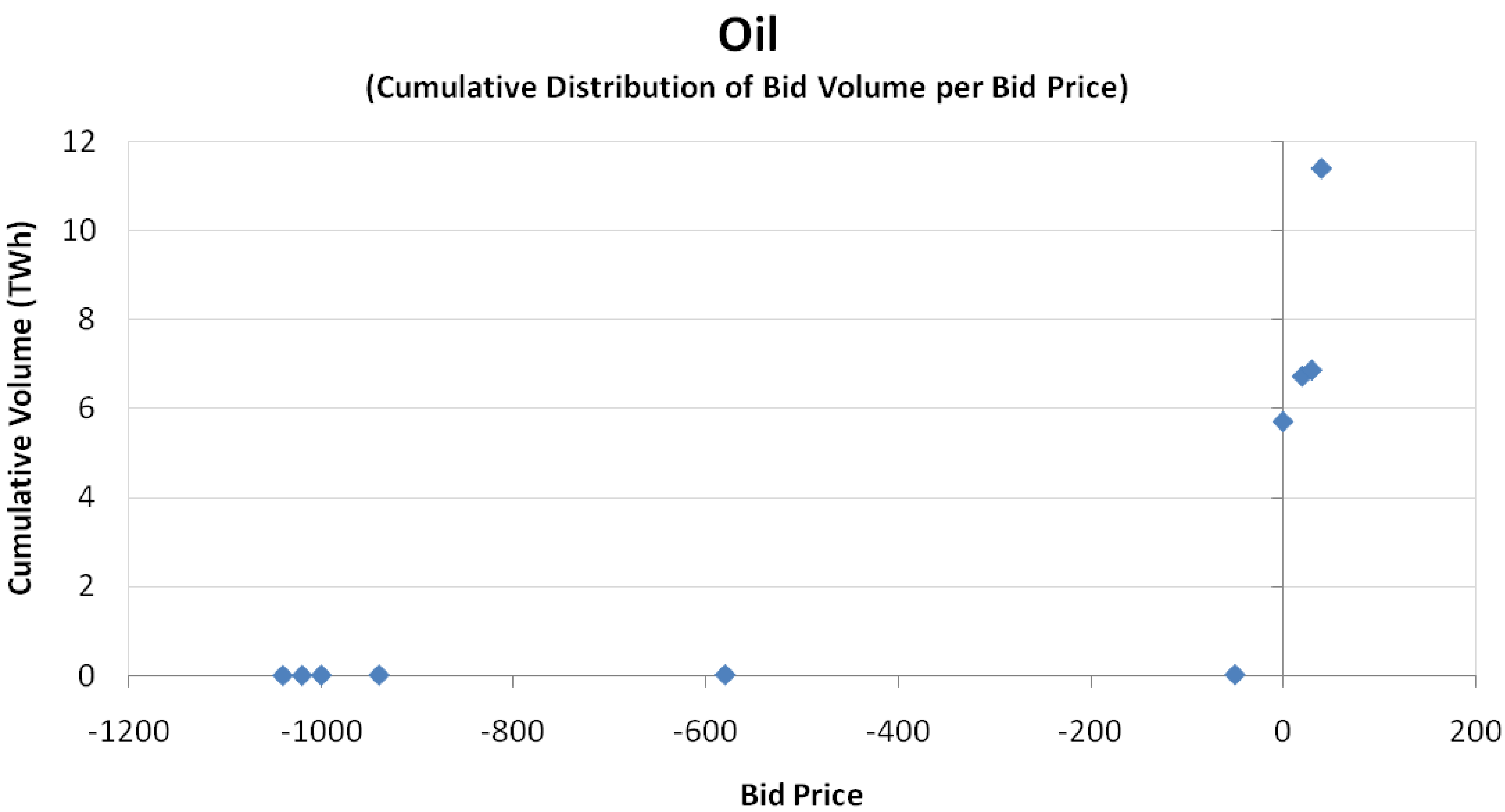
OCGT


OCGT
(Cumulative Distribution of Bid Volume per Bid Price)
12
10
8
6
4
2
0
Cumulative Volume (TWh)
-12000
-10000
-8000
-6000
-4000
-2000
0
2000
Bid Price

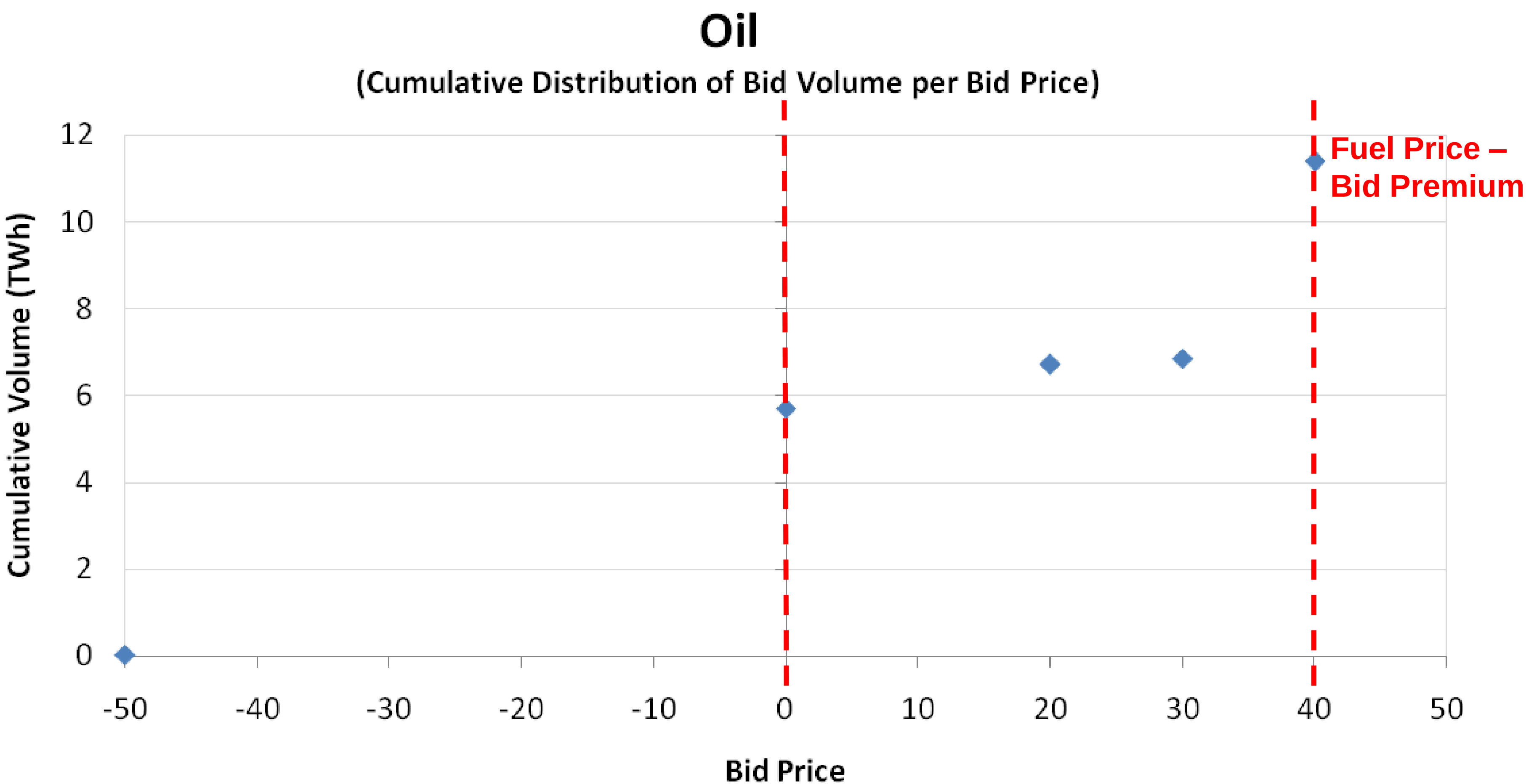
OCGT


OCGT
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
Bid Price
SO contracts
Fuel Price –
Bid Premium
Distillate?
12
10
8
6
4
2
0
-150
-100
-50
0
50
100
150
200
250
300
350
400
450

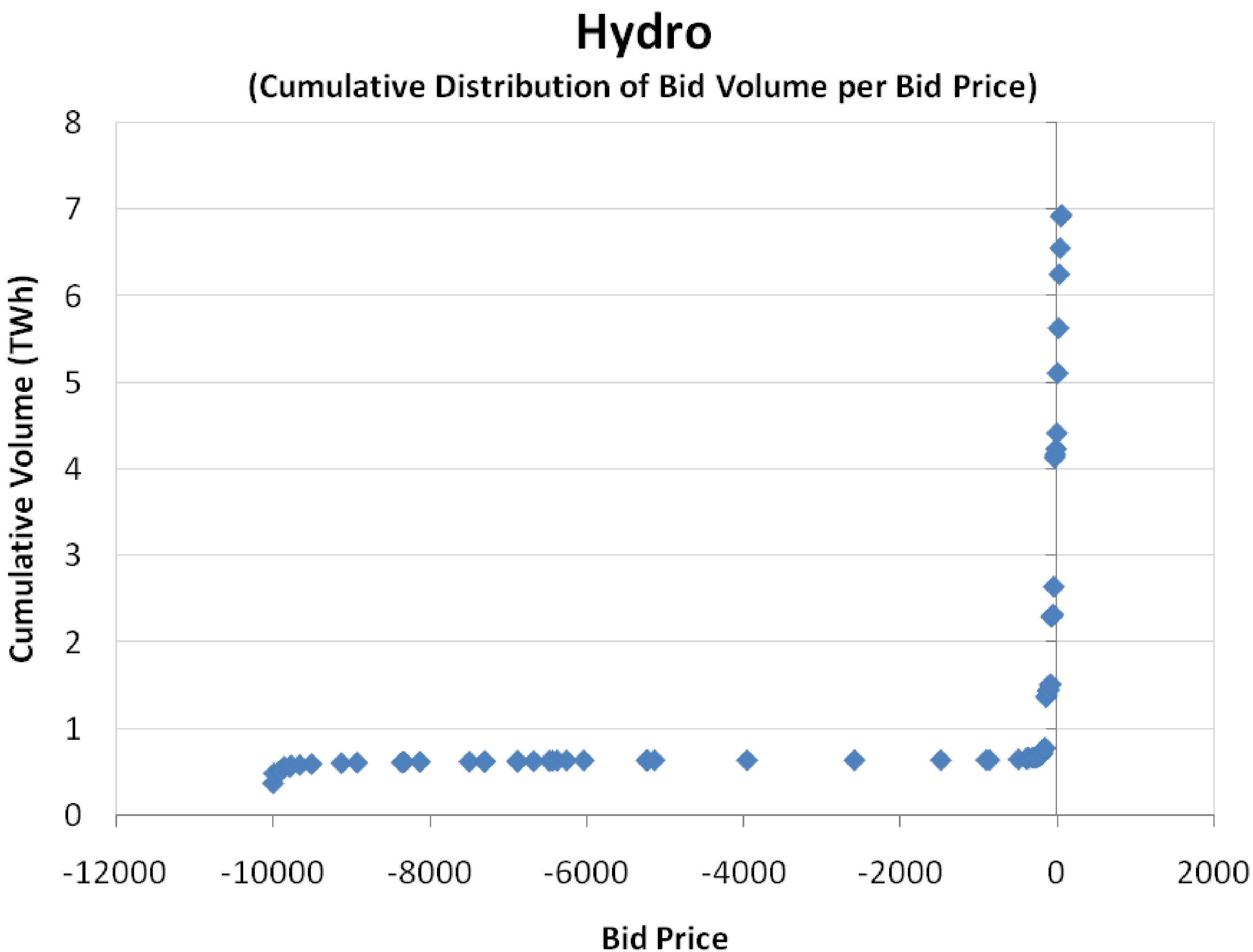
Oil


Oil
(Cumulative Distribution of Bid Volume per Bid Price)
12
10
8
6
4
2
0
Cumulative Volume (TWh)
-1200
-1000
-800
-600
-400
-200
0
200
Bid Price

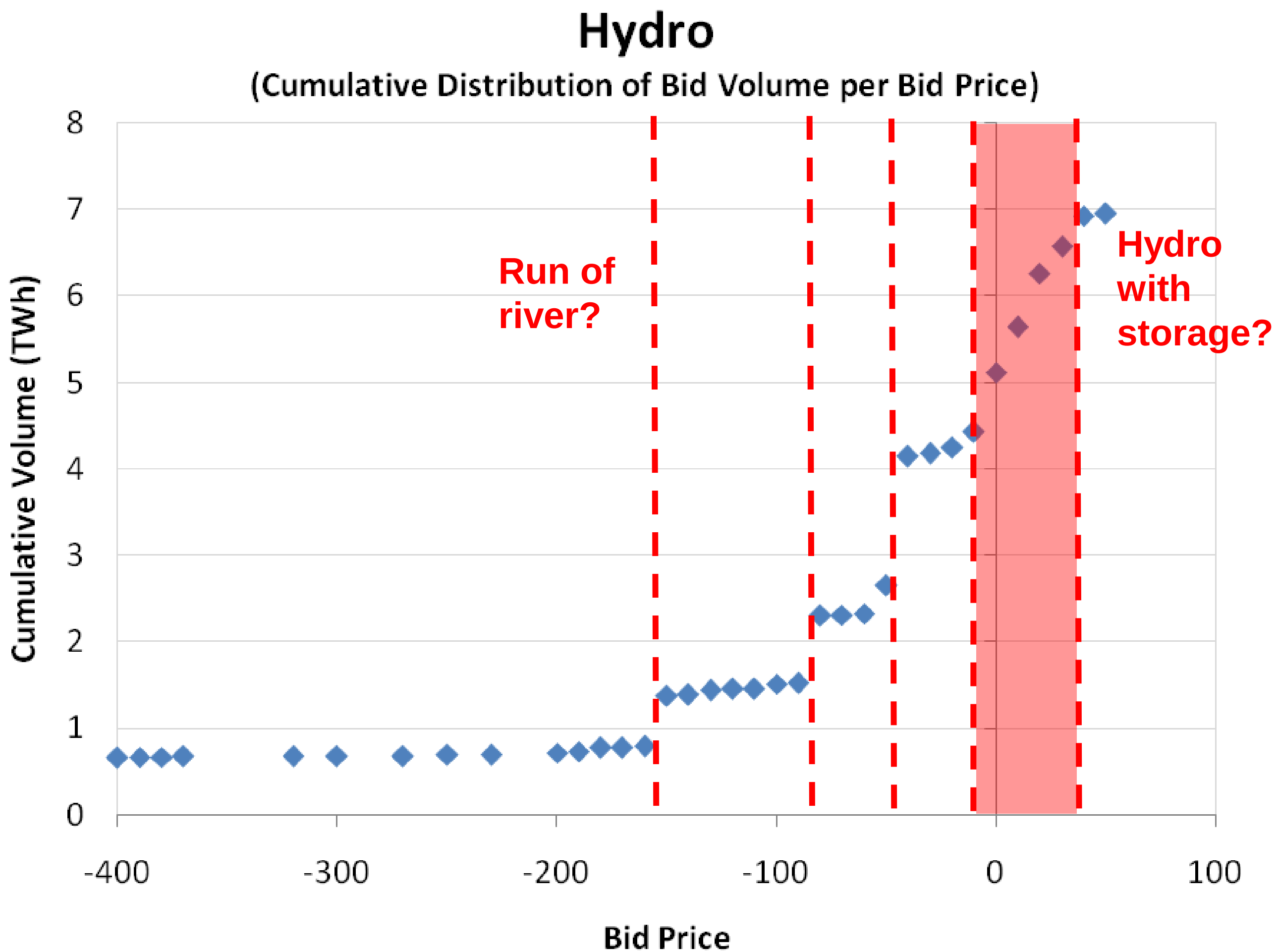
Oil


Oil
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
0
2
4
6
8
10
12
-50
-40
-30
-20
-10
0
10
20
30
40
50
Bid Price
Fuel Price –
Bid Premium

Hydro

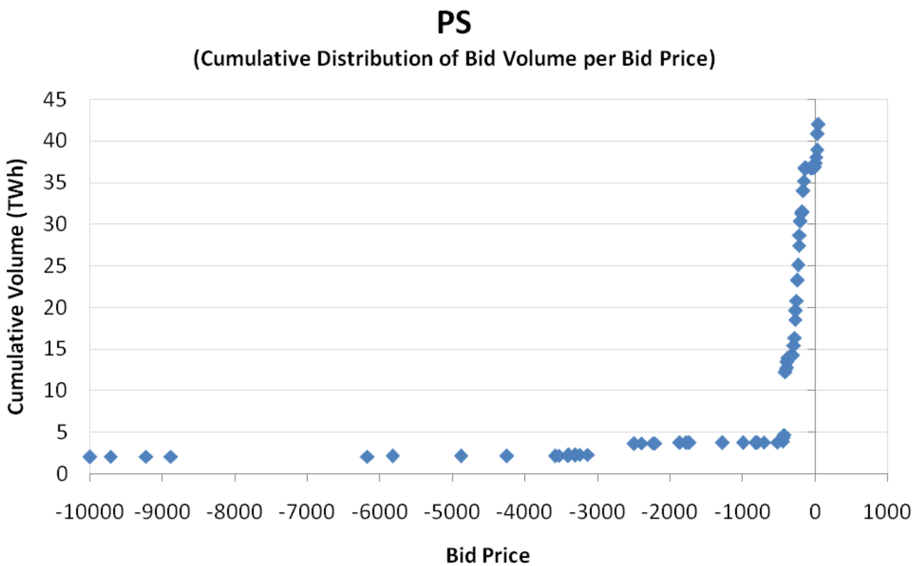

Hydro
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
8
7
6
5
4
3
2
1
0
-12000
-10000
-8000
-6000
-4000
-2000
0
2000
Bid Price

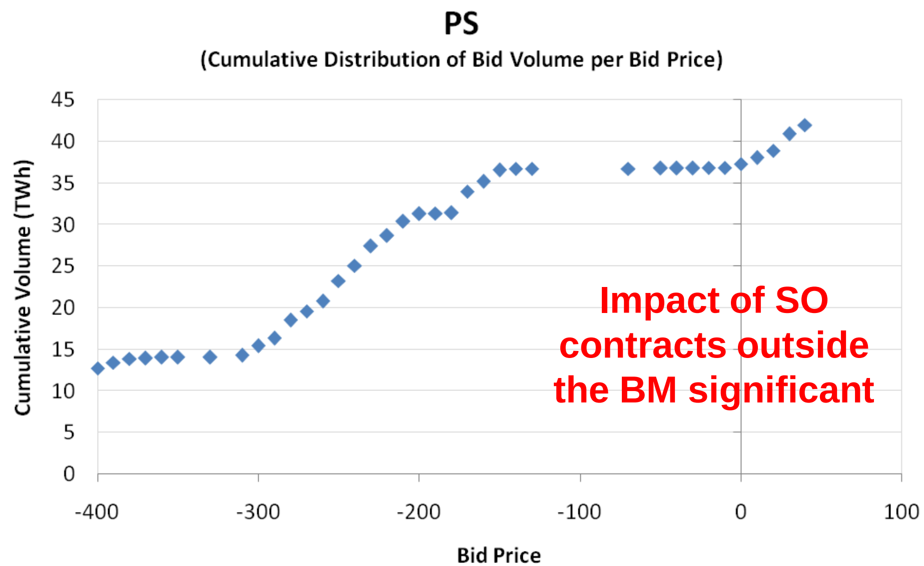
Hydro


Hydro
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
0
1
2
3
4
5
6
7
8
-400
-300
-200
-100
0
100
Bid Price
Run of river?
Hydro with storage?

Requested Review of Hydro Data

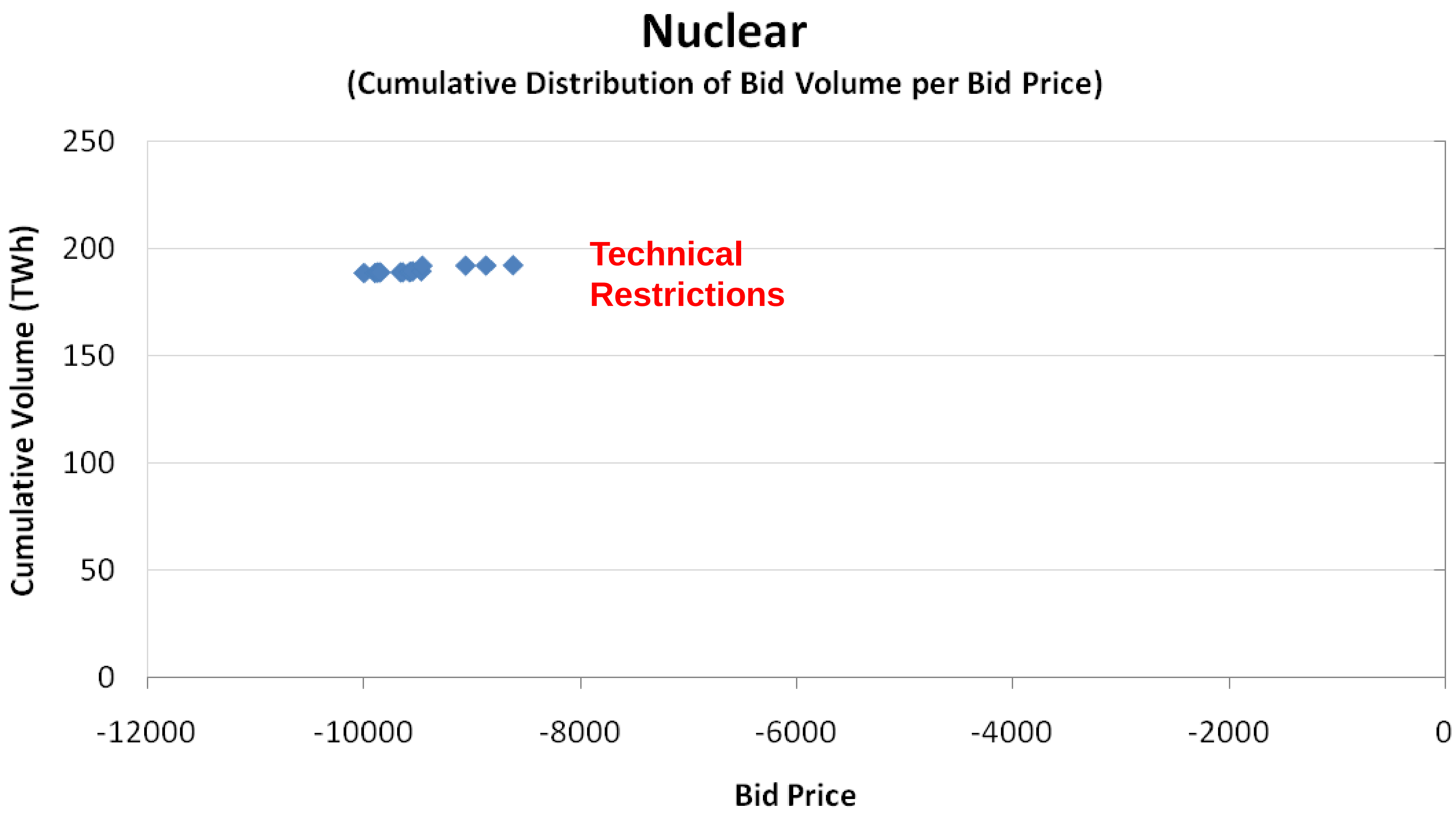
- Review of historic bid price data confirms that pumped storage plant <u>are excluded</u>
- Hydro graphs previously presented to the group are valid



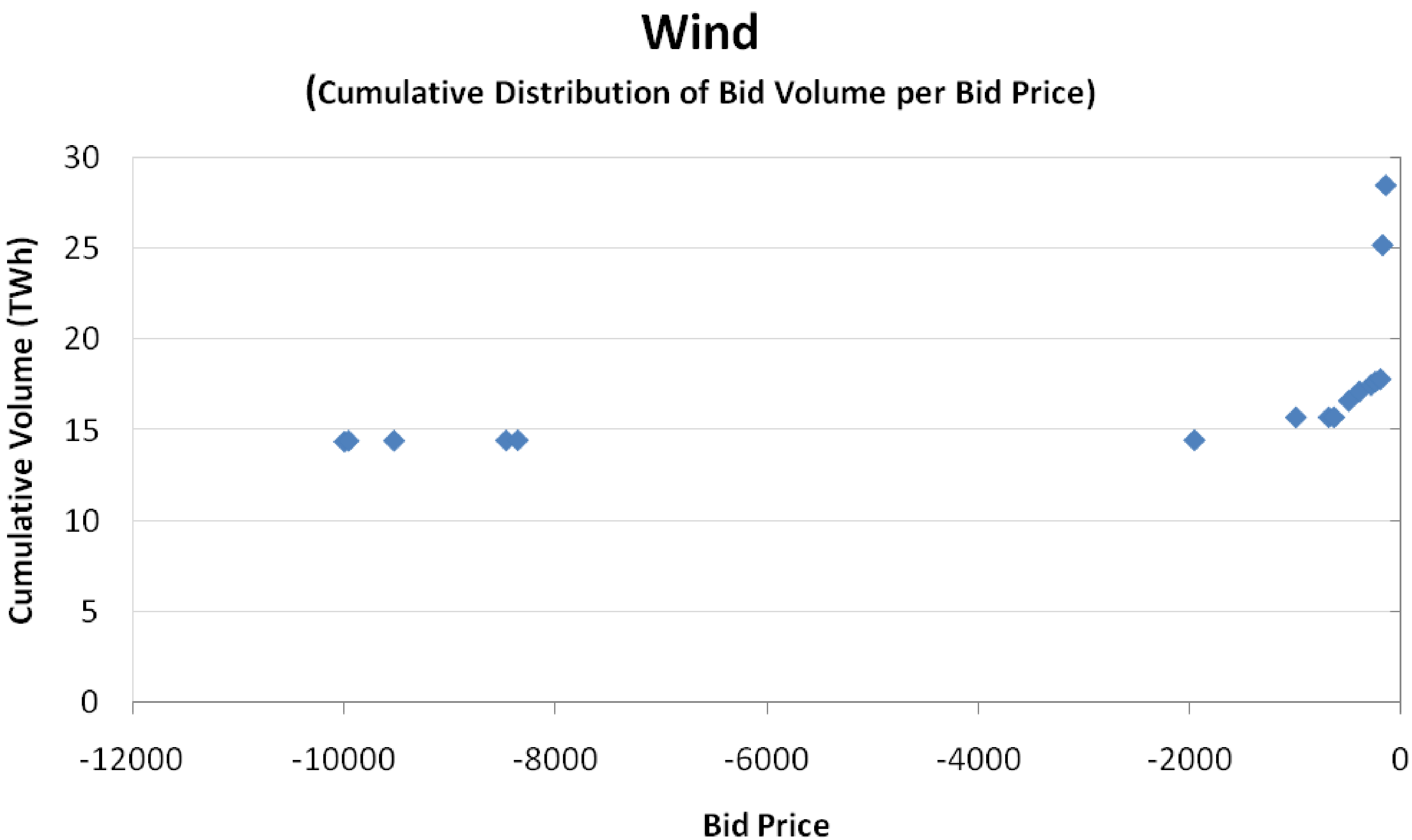


- Pumped storage graphs provided for clarity

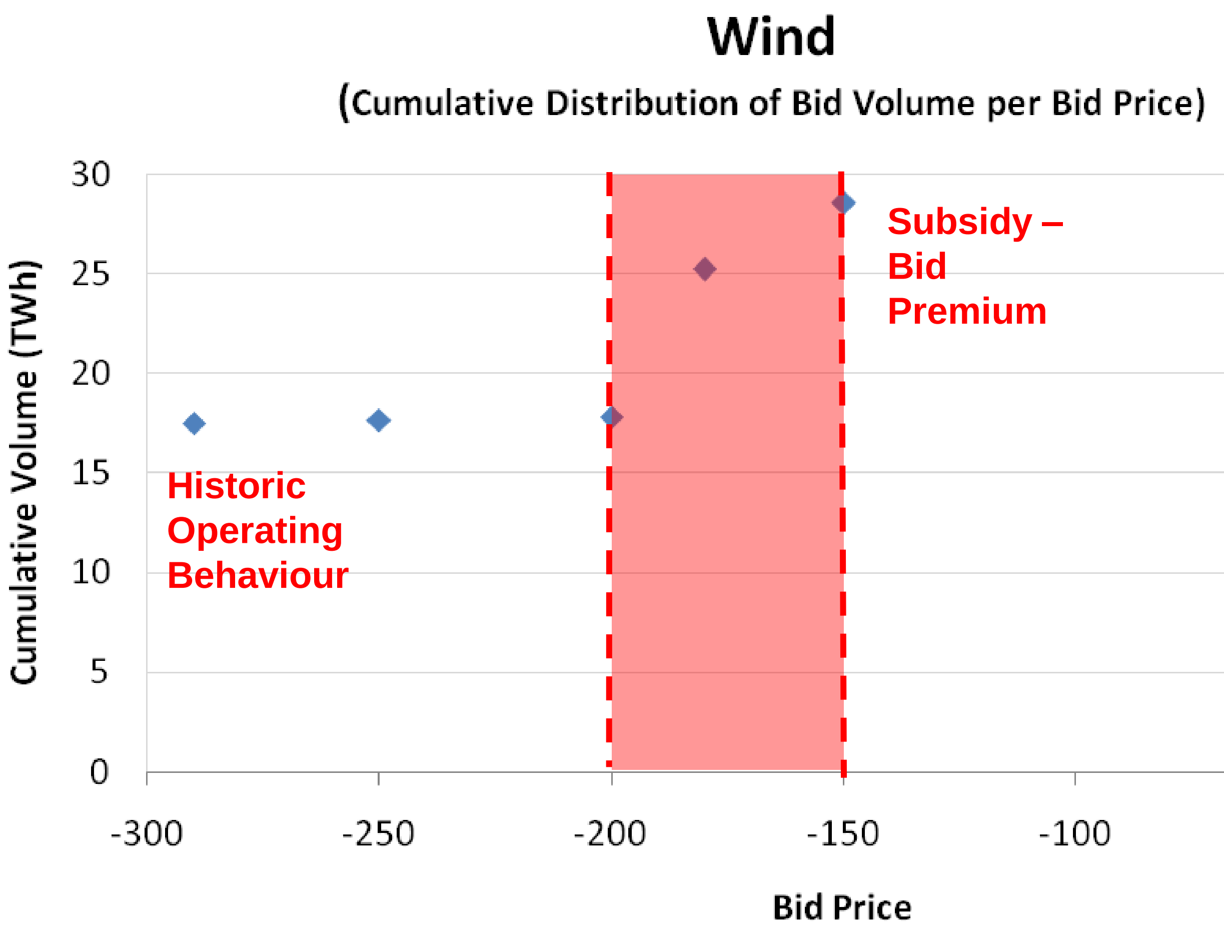
Nuclear


Nuclear
(Cumulative Distribution of Bid Volume per Bid Price)
Technical Restrictions
Cumulative Volume (TWh)
250
200
150
100
50
0
-12000
-10000
-8000
-6000
-4000
-2000
0
Bid Price

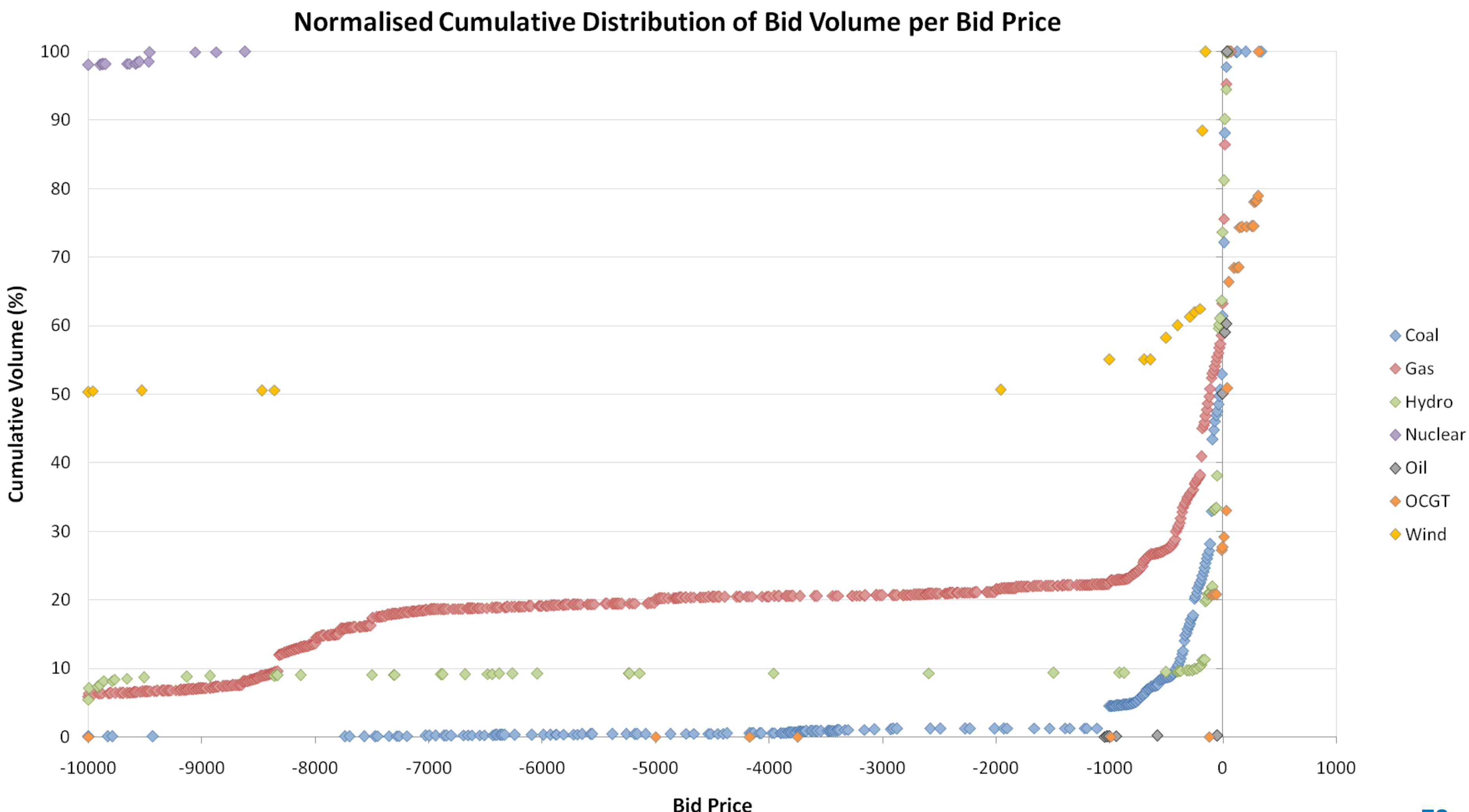
Wind


Wind
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
30
25
20
15
10
5
0
-12000
-10000
-8000
-6000
-4000
-2000
0
Bid Price

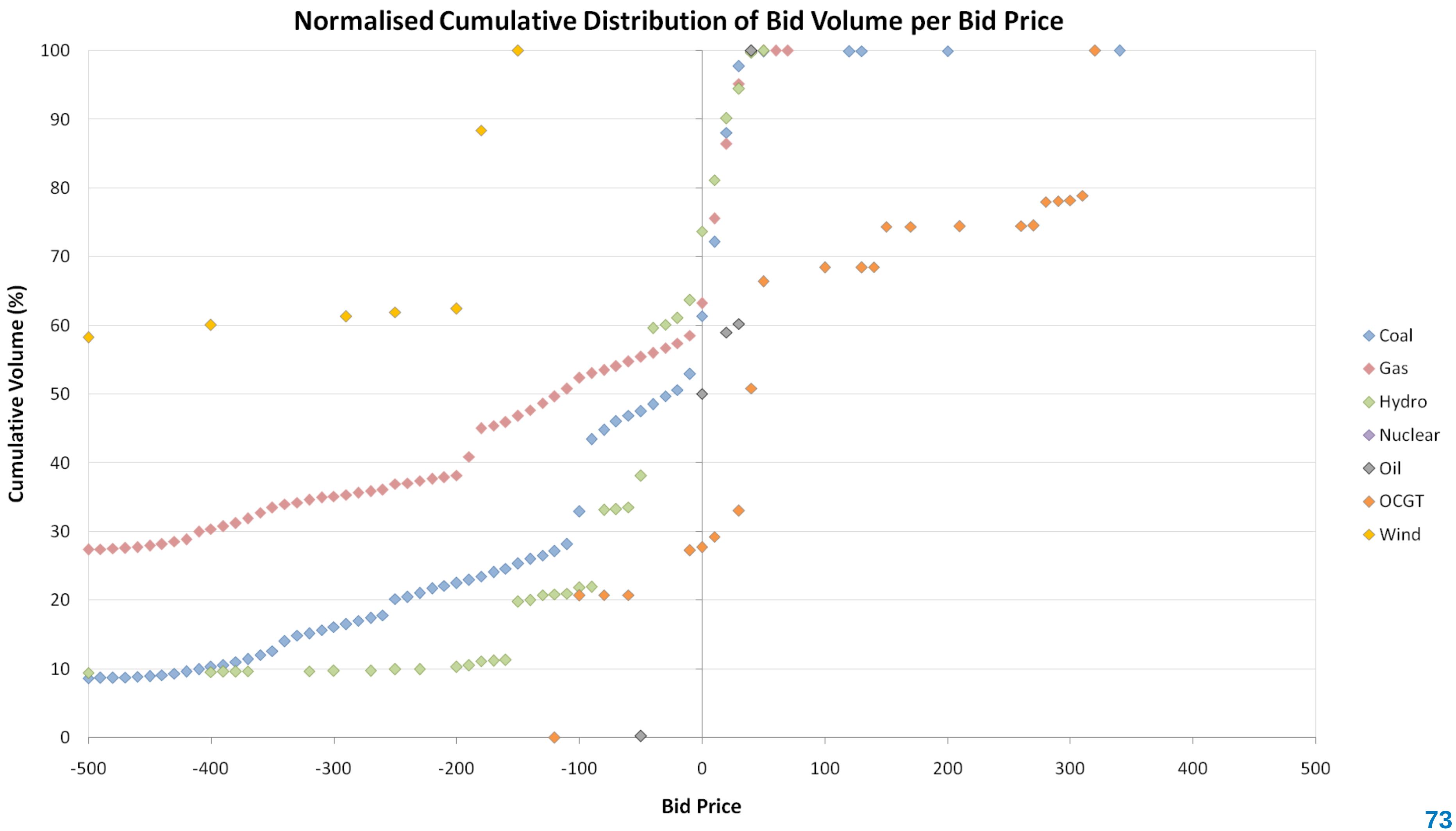
Wind


Wind
(Cumulative Distribution of Bid Volume per Bid Price)
Cumulative Volume (TWh)
30
25
20
15
10
5
0
-300
-250
-200
-150
-100
-50
0
Bid Price
Subsidy – Bid Premium
Historic Operating Behaviour

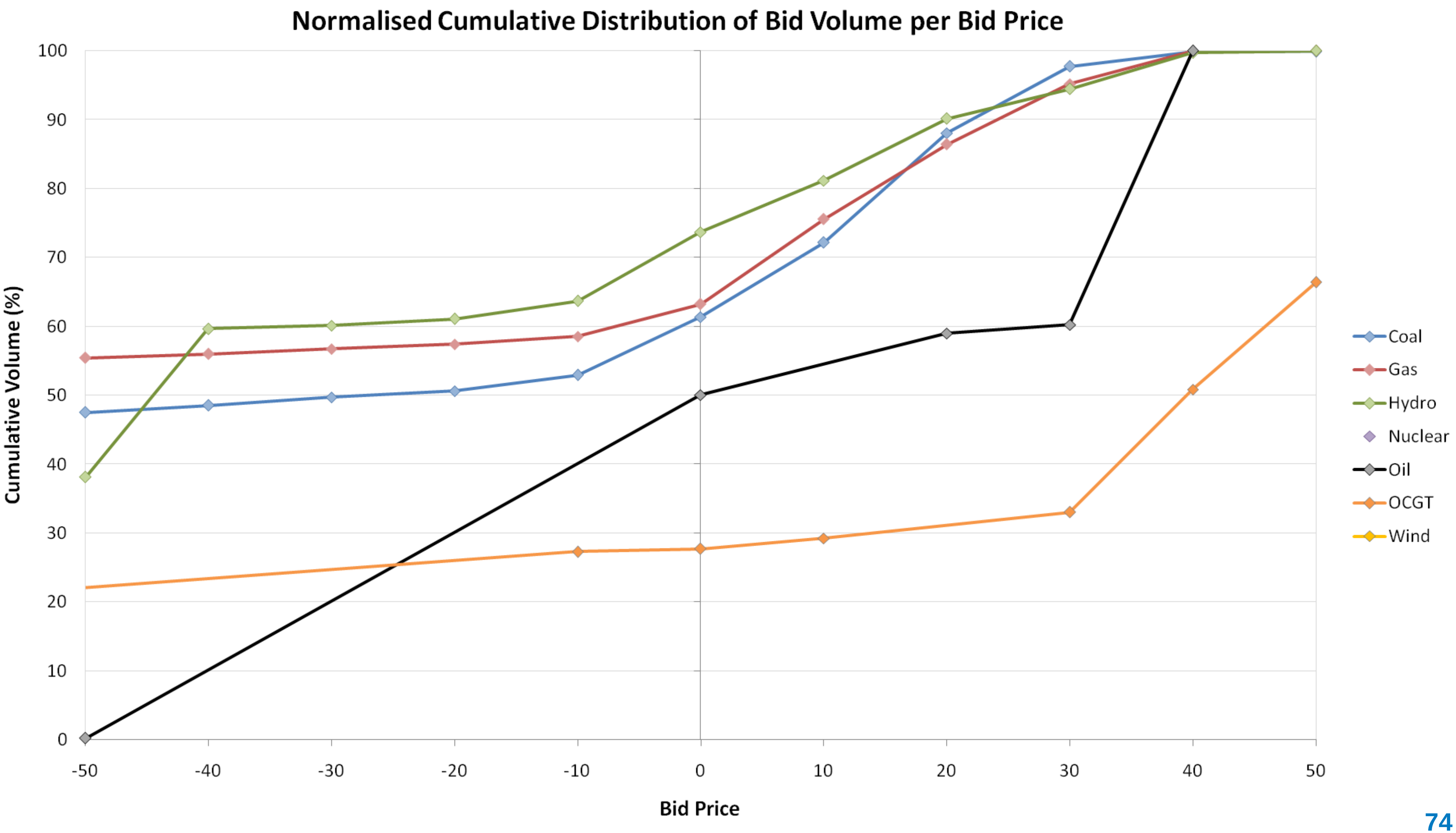
All Plant Types



All Plant Types



All Plant Types



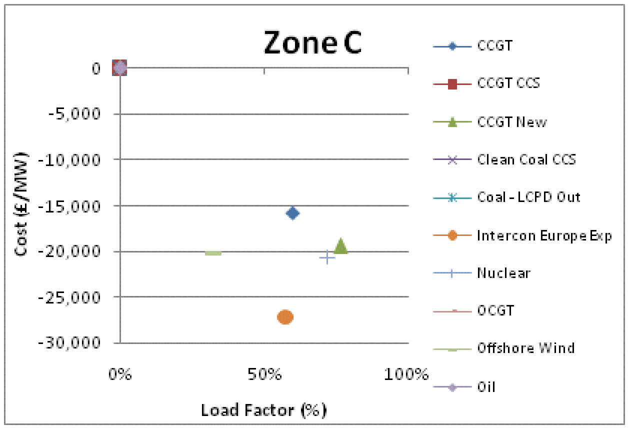
iii CMP213 – Diversity Work

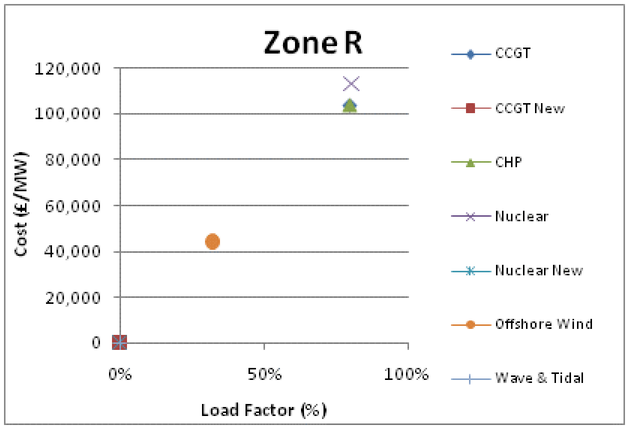
January 2013

Ivo Spreeuwenberg

Background – How have we got here? (i)

- Group initially considered simply annual LF vs. annual incr. constraint cost graphs, as presented to SCR WG in 2011

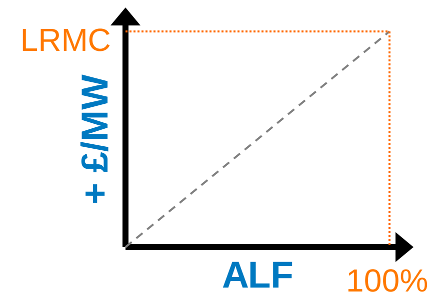




- Graphs for all zones across 2011/12, 2015/16 and 2019/20 presented to the group*
- Some WG members suggested that:
  - relationship upon which the Original is predicated appeared overly simplistic;
  - more information and explanation was required

*http://www.nationalgrid.com/NR/rdonlyres/25D67F32-8C6C-4EA4-9838-2B637FABD297/55216/AgendaItem5_TransmiT_WGMtg.pdf

Background – How have we got here? (ii)



- Comparison with annual incremental constraint costs based on a network planned to optimal capacity; i.e. where SRMC=LRMC

x-axis – ALF –

- Annual load factor = % annual output (100% = capacity = LRMC)

y-axis – +£/MW –

- Building blocks of annual incremental constraint costs investigated in more detail

Volume of Incremental Constraints (MWh)

i. Generator output over the year

ii. Correlation between generation running within an area

iii. Correlation with constraint times

X

Price of Incremental Constraints (£/MWh)

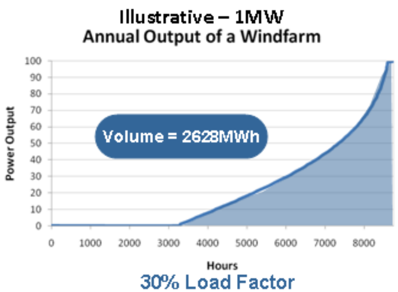
iv. Bid price of the marginal generator on the exporting side

v. Offer price of the marginal generator on the importing side

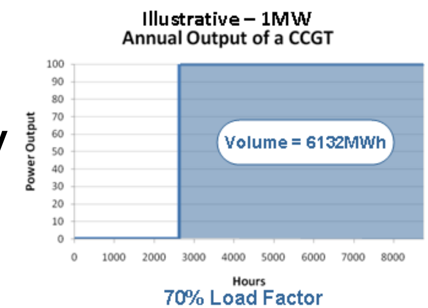
- (i) generator output, (iv) bid price and (v) offer price investigated and reasonably well understood

Background – How have we got here? (iii)

Output

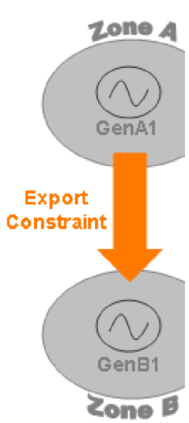


- Intermittent output driven predominately by wind (wind, tidal) → statistical



- Conventional output driven predominately by the market

Bids & Offers



Base Case Price =

$$\sum_{t=0}^{8760} (\underbrace{GenB1\_£/MW}_{Offer} - \underbrace{GenA1\_£/MW}_{Bid})t$$

Incremental Price =

$$\sum_{t=0}^{8760} (GenB1\_£/MW - GenA1\_£/MW)t$$

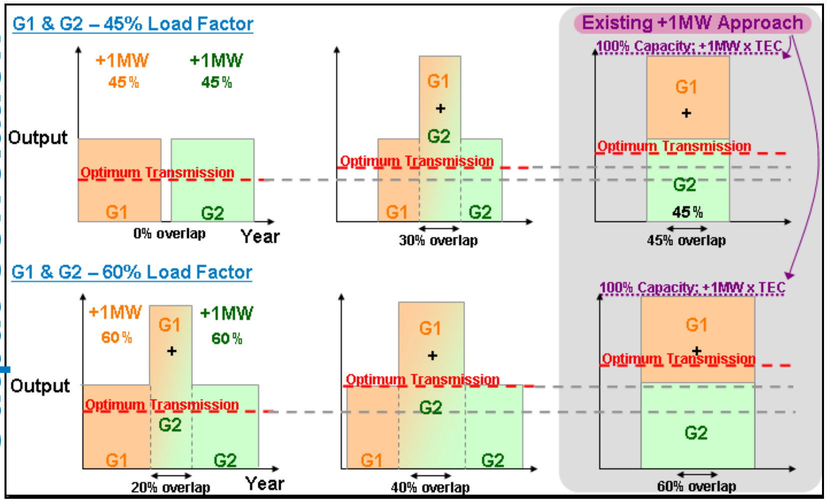
- In market model:

  Offer = 1.6 x SRMC; Bid = 0.6 x SRMC

- Therefore, when bids and offers accepted from marginal plant: constraint price = SMP

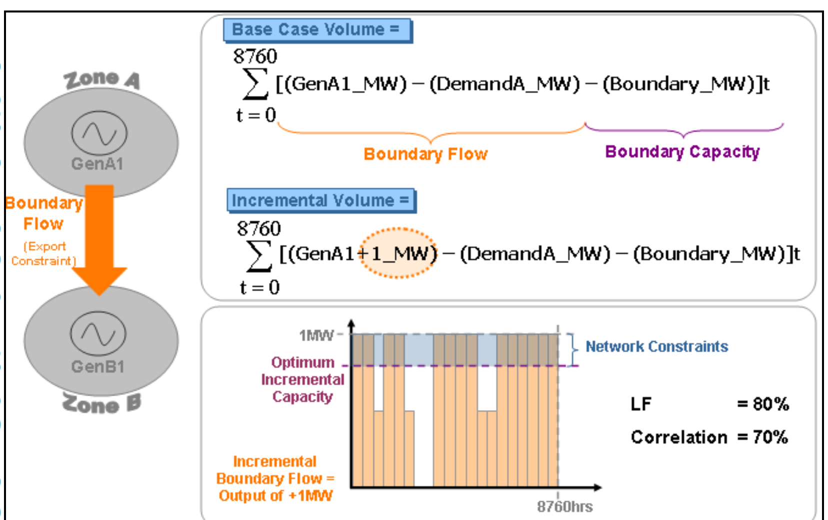
Background – How have we got here? (iv)

Output Correlation



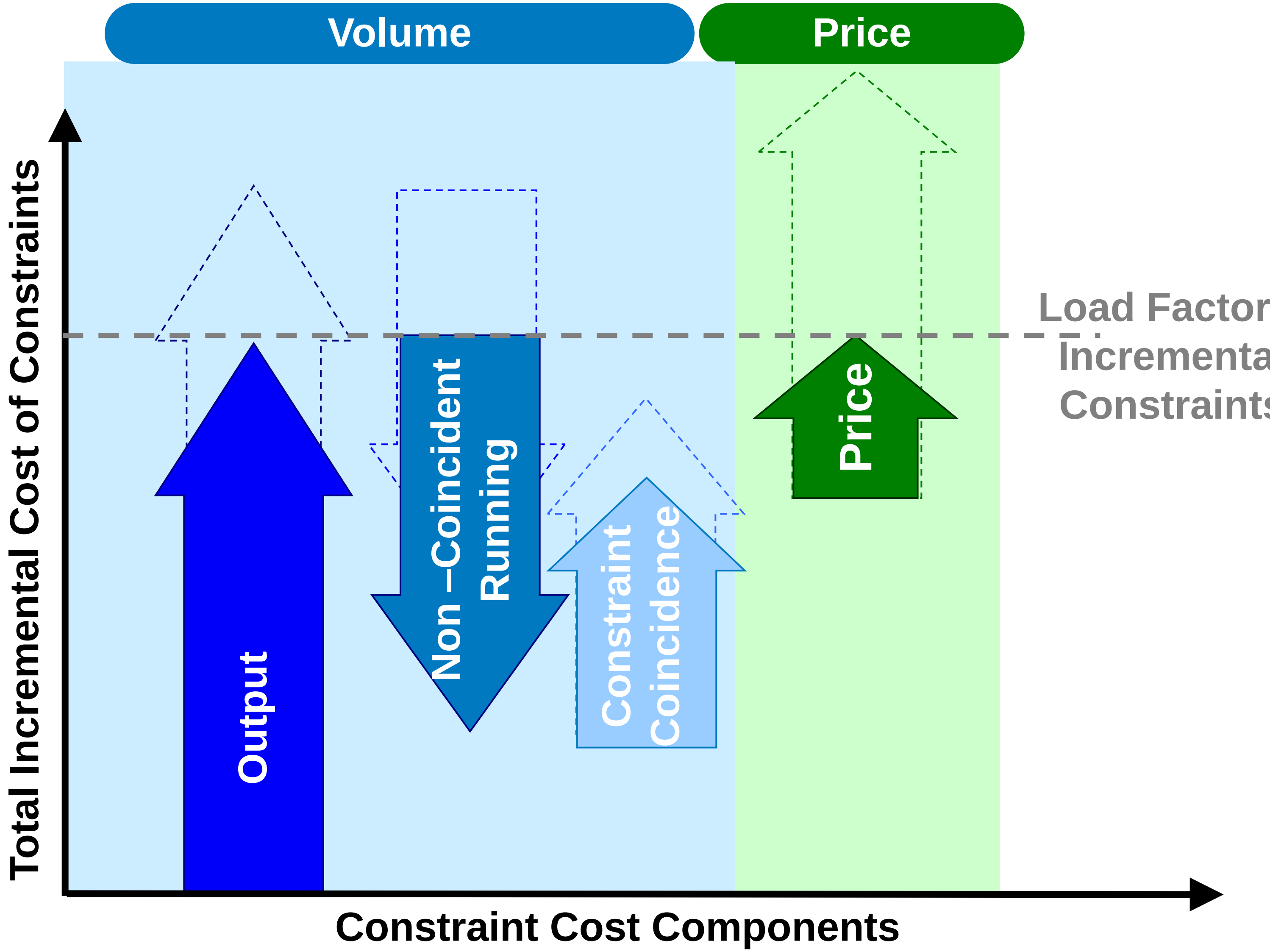
- Relative timing of generation output
- Availability and merit order
- Inherent part of market model for conventional plant
- Market modelling does not account for statistical availability between intermittent plant of different types

Constraint Correlation

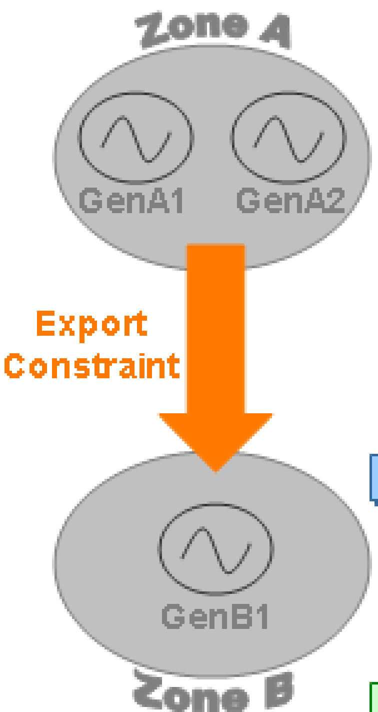


- Generation output vs. demand and boundary capacity
- Boundary capacity assumed fixed
- Correlation with demand
- Inherent part of market model

Background – How have we got here? (v)



Background – How have we got here? (vi)



Base Case Volume =

$$\sum_{t=0}^{8760} [\underbrace{(GenA1_{MW} + GenA2_{MW})}_{\text{Annual Output + Correlation of Generation}} \overbrace{- (DemandA_{MW}) - (Boundary_{MW})}^{\text{Correlation with Constraints}}]t$$

Base Case Price =

$$\sum_{t=0}^{8760} (GenB1_{£/MW} - GenA2_{£/MW})t$$

(*GenA2 assumed marginal)

Incremental Volume =

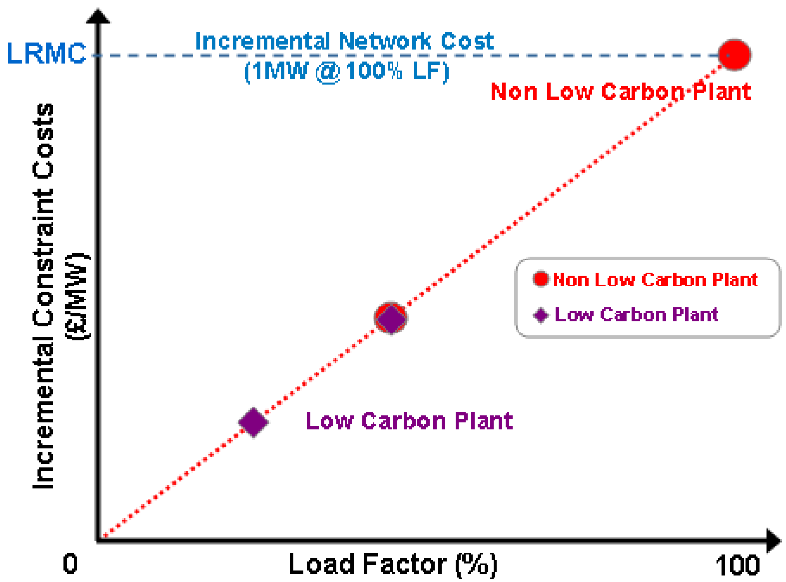
$$\sum_{t=0}^{8760} [(GenA1_{MW} + 1_{MW} + GenA2_{MW}) - (DemandA_{MW}) - (Boundary_{MW})]t$$

Incremental Price =

$$\sum_{t=0}^{8760} (GenB1_{£/MW} - GenA2_{£/MW})t$$

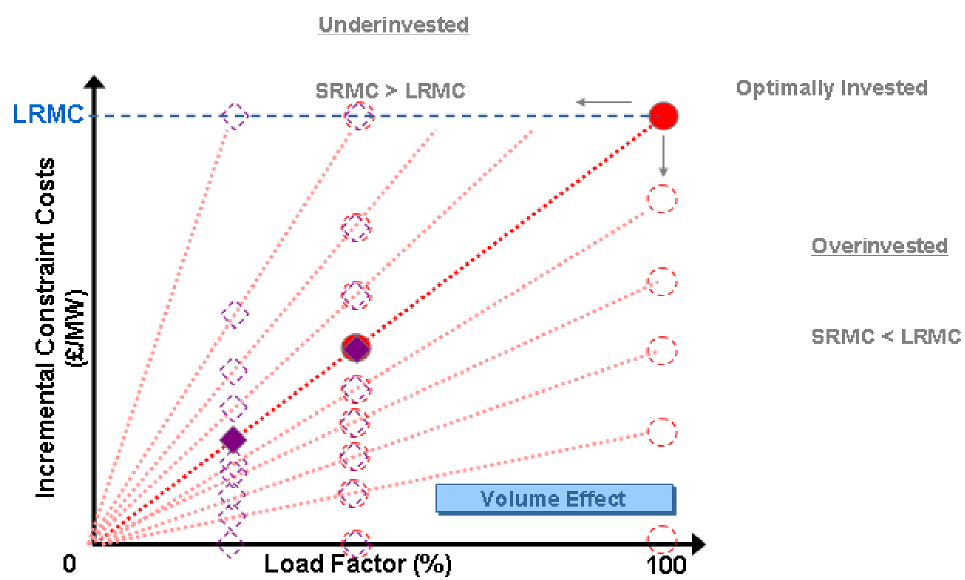
Incremental Constraint Cost = Incremental (Volume x Price) – Base Case (Volume x Price)

Background – How have we got here? (vii)



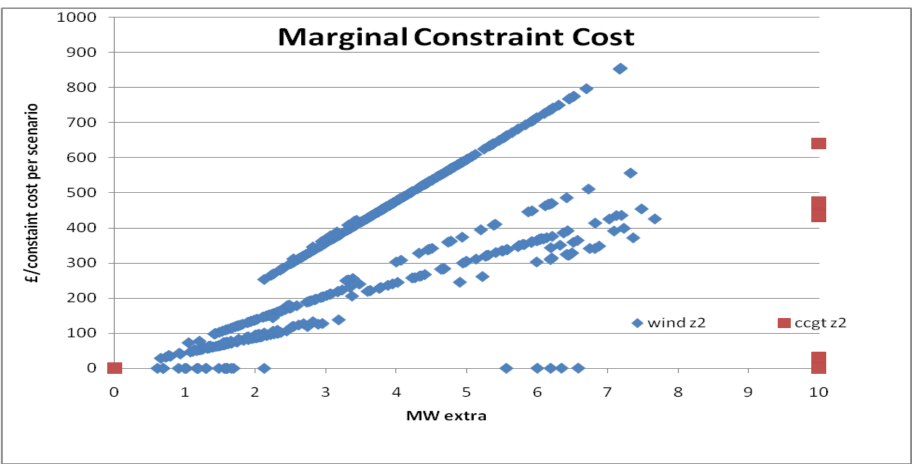
- LRMC set by annual incremental constraint impact of fictitious 100% annual LF, marginal generator
- Equivalent to incremental cost arising from Transport model

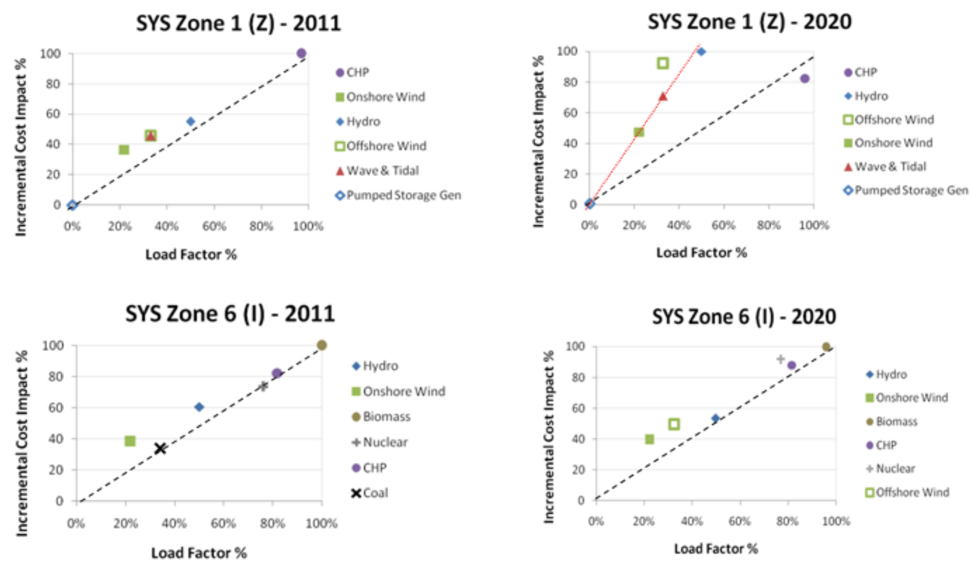
- Slope of the line set by optimum network capacity
- Fixes boundary capacity impact on correlation with constraints



Background – How have we got here? (viii)

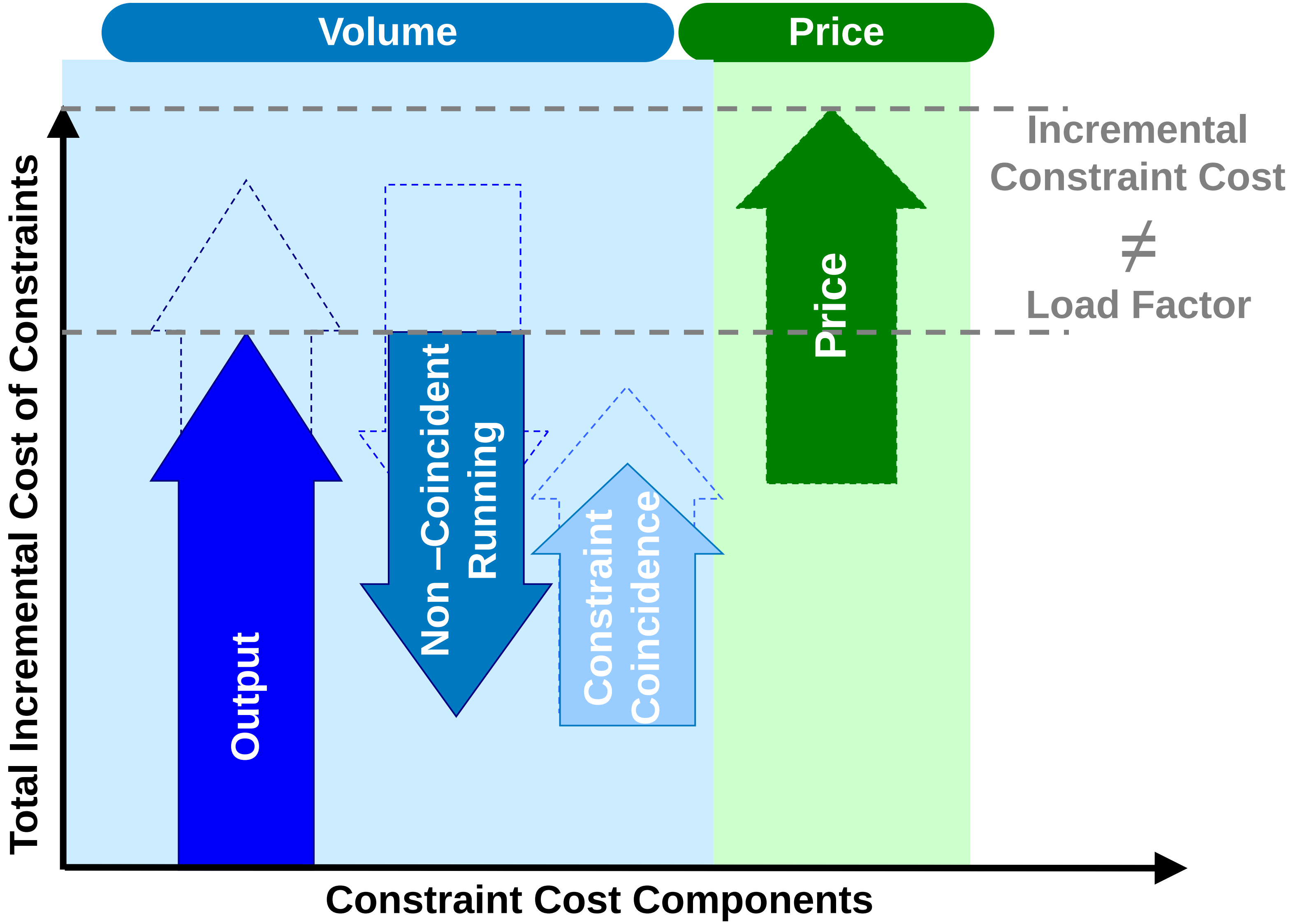
- Closer consideration of the load factor versus incremental constraint cost graphs by the Workgroup showed degradation of relationship in some zones





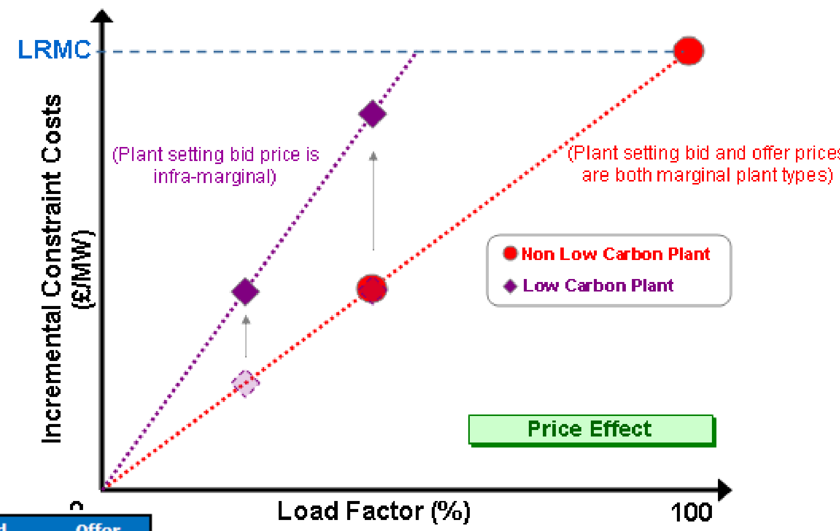
- Degradation occurs where certain generation plant types dominate in an area of the network
- Constraint cost elements do not broadly counter balance

Background – How have we got here? (ix)



Background – How have we got here? (x)

- Price effect observed through analysis of load factor versus constraint cost graphs
- Low (negative) bid price plant lead to divergence



Fuel Type	Fuel grouping	CO2 t/MWh	CO2 £/MWh	Fuel	SRMC	Bid	Offer
Hydro	Renewables	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00
Offshore Wind	Renewables	0.00	£0.00	£0.01	£0.01	-£100.00	£0.00
Onshore Wind	Renewables	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00
Wave & Tidal	Renewables	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00
Nuclear	Nuclear	0.00	£0.00	£6.50	£6.50	£0.00	£10.40
Nuclear New	Nuclear	0.00	£0.00	£6.50	£6.50	£0.00	£10.40
Biomass	Renewables	0.00	£0.00	£25.00	£25.00	£15.00	£40.00
CHP	Gas	0.22	£5.72	£21.99	£27.71	£16.63	£44.34
CHP New	Gas	0.22	£5.72	£21.99	£27.71	£16.63	£44.34
CCGT CCS	Gas	0.00	£0.00	£39.99	£39.99	£23.99	£63.98
Clean Coal CCS	Coal	0.00	£0.00	£37.63	£37.63	£22.58	£60.20
CCGT New	Gas	0.34	£8.88	£34.13	£43.01	£25.80	£68.81
Gas - Other	Gas	0.34	£8.88	£34.13	£43.01	£25.80	£68.81
CCGT	Gas	0.36	£9.36	£35.99	£45.35	£27.21	£72.56
Coal - LCPD In	Coal	0.93	£24.07	£31.98	£56.05	£33.63	£89.68
Coal - LCPD Out	Coal	0.93	£24.07	£31.98	£56.05	£33.63	£89.68
Coal - Non LCPD	Coal	0.93	£24.07	£31.98	£56.05	£33.63	£89.68
Oil	Peaking	0.72	£18.72	£111.42	£130.14	£78.08	£208.22
OCGT	Peaking	0.84	£21.84	£149.33	£171.17	£102.70	£273.88
User defined	User defined	0.84	£21.84	£149.33	£171.17	£102.70	£273.88
Curtail	Curtail	0.00			£4,000.00	£4,000.00	£4,000.00

Background – How have we got here? (xi)

- ELSI utilises planning assumptions
- Historic bid prices also investigated by the group to corroborate

ELSI

Fuel Type	Fuel grouping	CO2 t/MWh	CO2 £/MWh	Fuel	SRMC	Bid	Offer
Hydro	Renewables	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00
Offshore Wind	Renewables	0.00	£0.00	£0.01	£0.01	-£100.00	£0.00
Onshore Wind	Renewables	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00
Wave & Tidal	Renewables	0.00	£0.00	£0.01	£0.01	-£50.00	£0.00
Nuclear	Nuclear	0.00	£0.00	£6.50	£6.50	£0.00	£10.40
Nuclear New	Nuclear	0.00	£0.00	£6.50	£6.50	£0.00	£10.40
Biomass	Renewables	0.00	£0.00	£25.00	£25.00	£15.00	£40.00
CHP	Gas	0.22	£5.72	£21.99	£27.71	£16.63	£44.34
CHP New	Gas	0.22	£5.72	£21.99	£27.71	£16.63	£44.34
CCGT CCS	Gas	0.00	£0.00	£39.99	£39.99	£23.99	£63.98
Clean Coal CCS	Coal	0.00	£0.00	£37.63	£37.63	£22.58	£60.20
CCGT New	Gas	0.34	£8.88	£34.13	£43.01	£25.80	£68.81
Gas - Other	Gas	0.34	£8.88	£34.13	£43.01	£25.80	£68.81
CCGT	Gas	0.36	£9.36	£35.99	£45.35	£27.21	£72.56
Coal - LCPD In	Coal	0.93	£24.07	£31.98	£56.05	£33.63	£89.68
Coal - LCPD Out	Coal	0.93	£24.07	£31.98	£56.05	£33.63	£89.68
Coal - Non LCPD	Coal	0.93	£24.07	£31.98	£56.05	£33.63	£89.68
Oil	Peaking	0.72	£18.72	£111.42	£130.14	£78.08	£208.22
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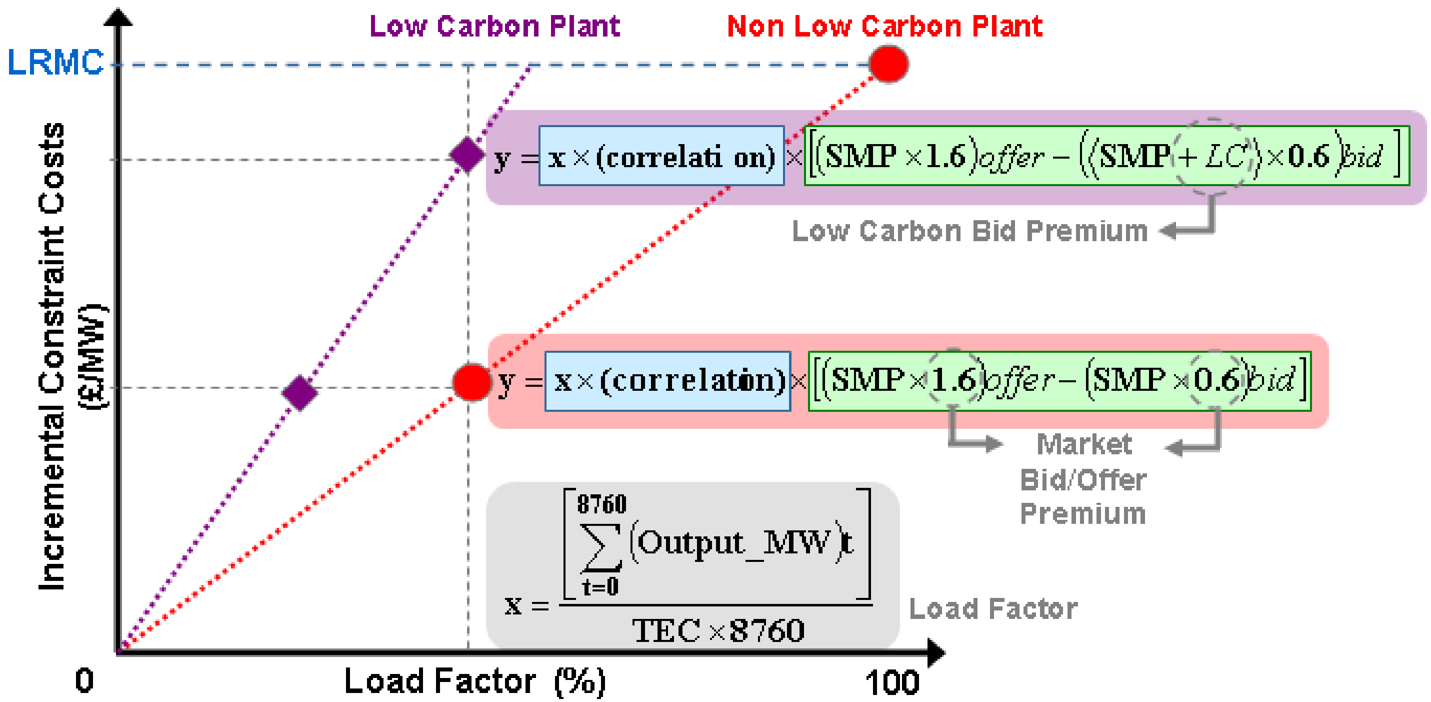
User defined	User defined	0.84	£21.84	£149.33	£171.17	£102.70	£273.88
Curtail	Curtail	0.00			£4,000.00	£4,000.00	£4,000.00

Bringing together observations and theory

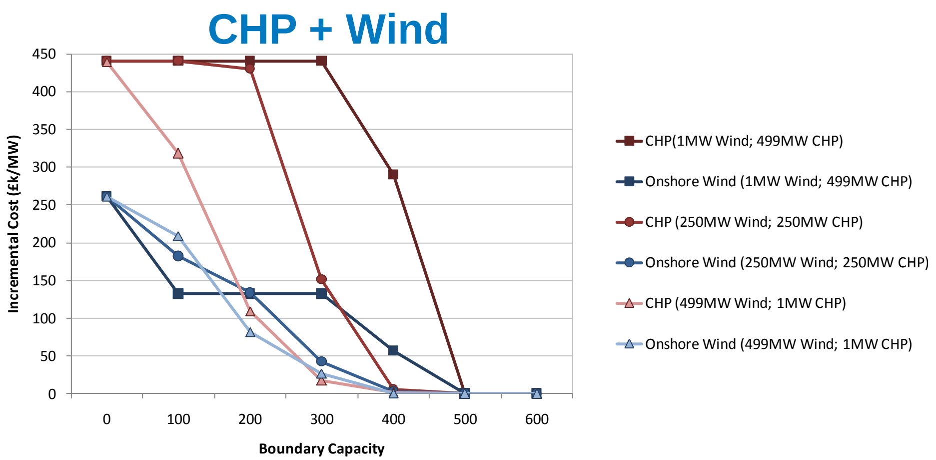
- Relationship explored in WG consultation and set out as:

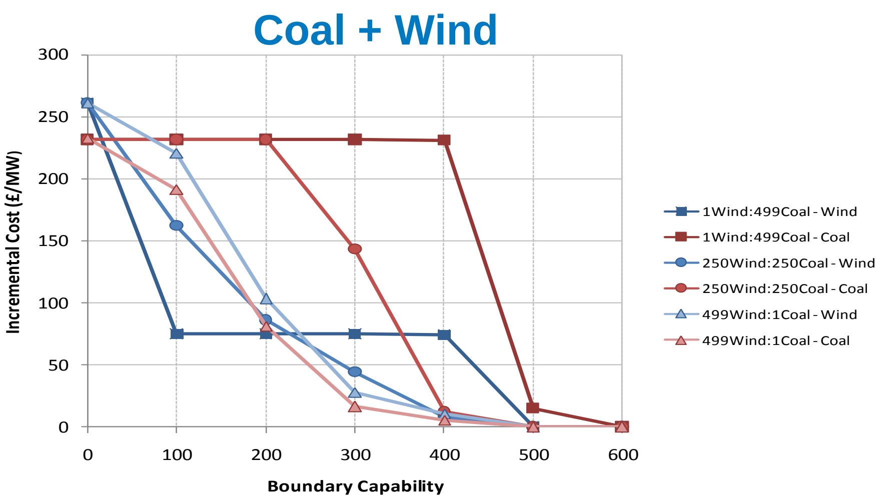


- Linear Load Factor vs. Incr. Cost relationship when:
  - correlation x price effect = 1 → components counter balance
  - slope of line = 1

Effects Tested in Market Model

- Analysis presented to group using Gone Green scenario over several years in July 2012; existing planning zones used
- Any methodology should be robust regardless of scenario

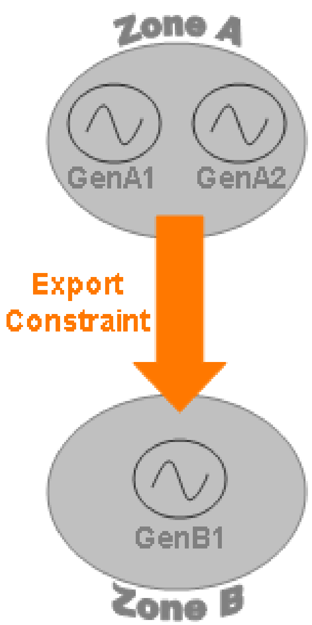




- Further testing and analysis of relationship in ‘test zone’
- Early analysis discussed with the group on November 6th

Effects Tested in Market Model

- Maintain unconstrained dispatch from ‘Gone Green’ scenario, but simplify to 2 zone transmission network in order to unpick effects
- Half-way house between ***top down*** full network analysis presented throughout 2011/2012 and ***bottom up*** theory developed by the Workgroup and set out in the consultation



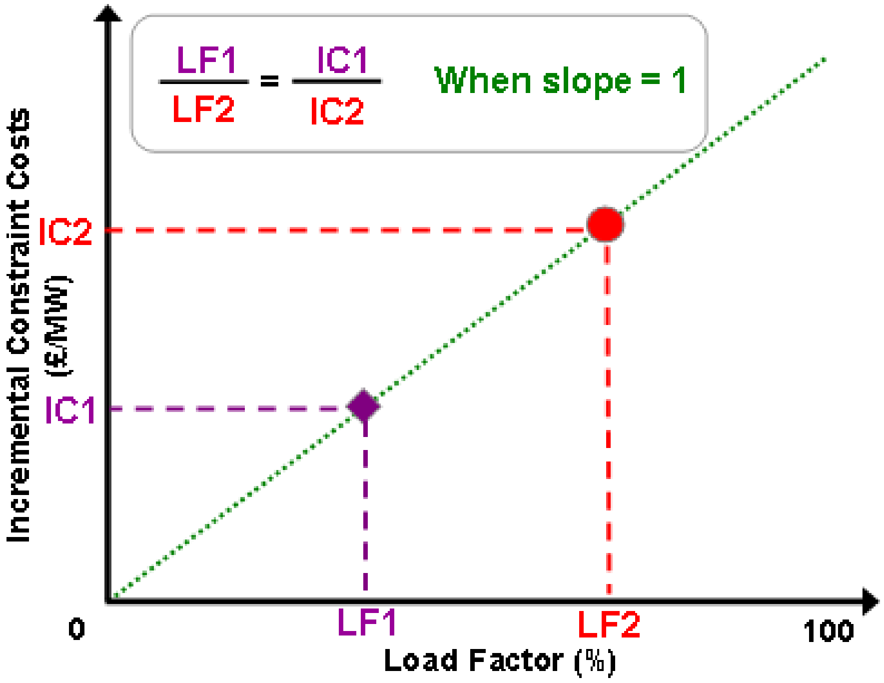
- Method: leave 500MW of generation and consider varying proportions of different plant types and varying boundary capacity into/out of the zone under consideration
  - Onshore Wind + CHP; Export; 2011
  - Onshore Wind + Coal; Export; 2011
  - Onshore Wind + CHP; Export; 2020
  - Onshore Wind + CHP; Import; 2011
  - Onshore Wind + Coal; Import; 2011
  - Onshore Wind + CHP; Import; 2020
  - Offshore Wind + CHP; Export; 2011

Effects Tested in Market Model

For each scenario:			
Wind MW	Conv. MW		Boundary MW
1	499		
150	350		0
250	250		100
300	200		200
350	150		300
400	100		400
450	50		500
499	1		600

- Each boundary capacity level analysed for each generation background

Effects Tested in Market Model

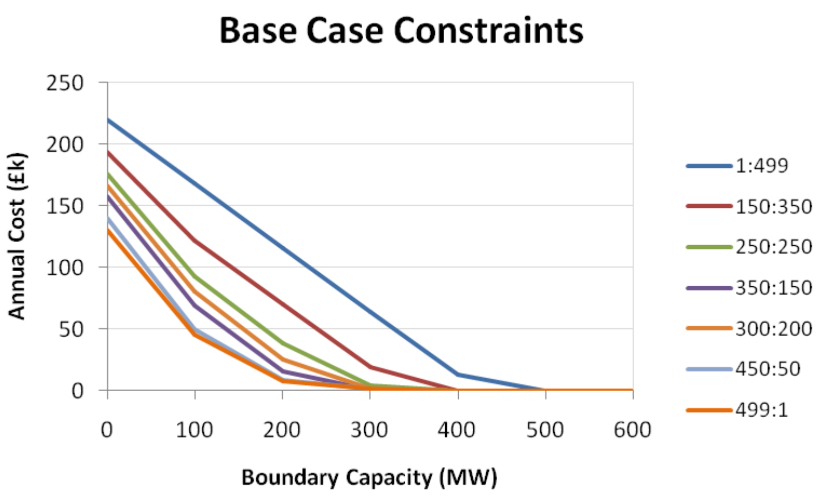


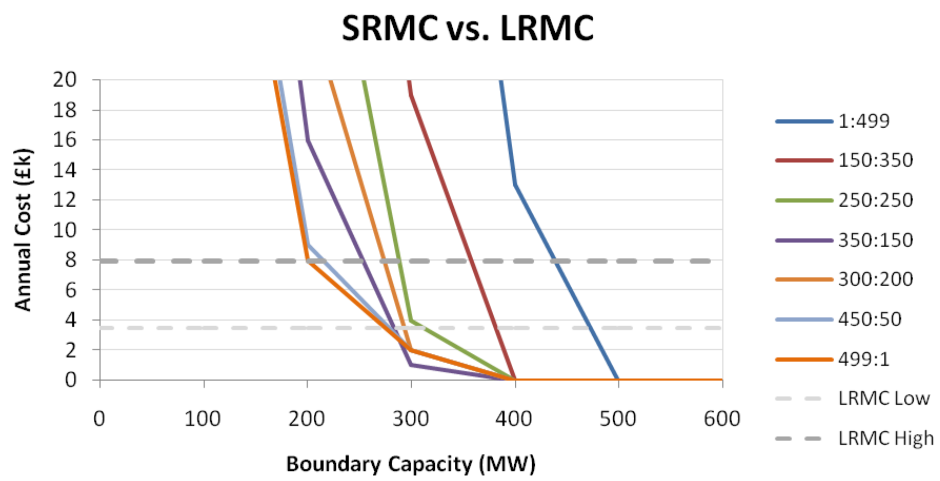
- LF1 = Intermittent (Wind)
- LF2 = Conventional (Coal/CHP)

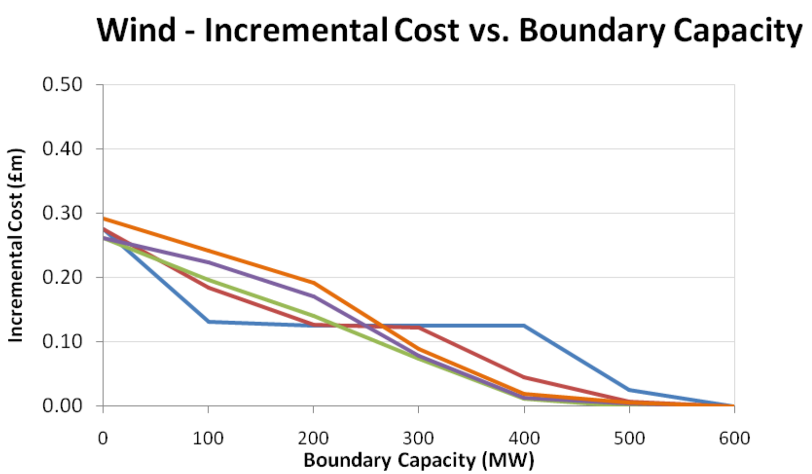
- Annual incremental constraint costs vary in proportion to annual load factor when:

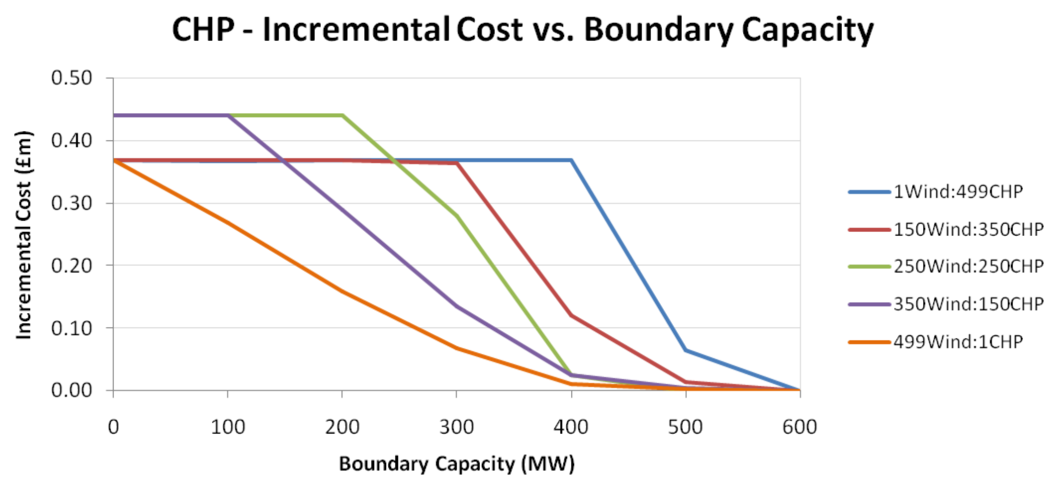
  slope of line = 1

Onshore Wind + CHP; Export; 2011



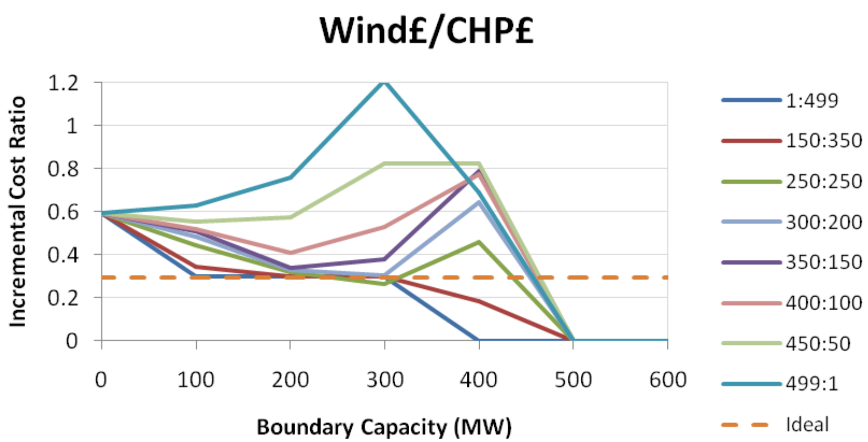






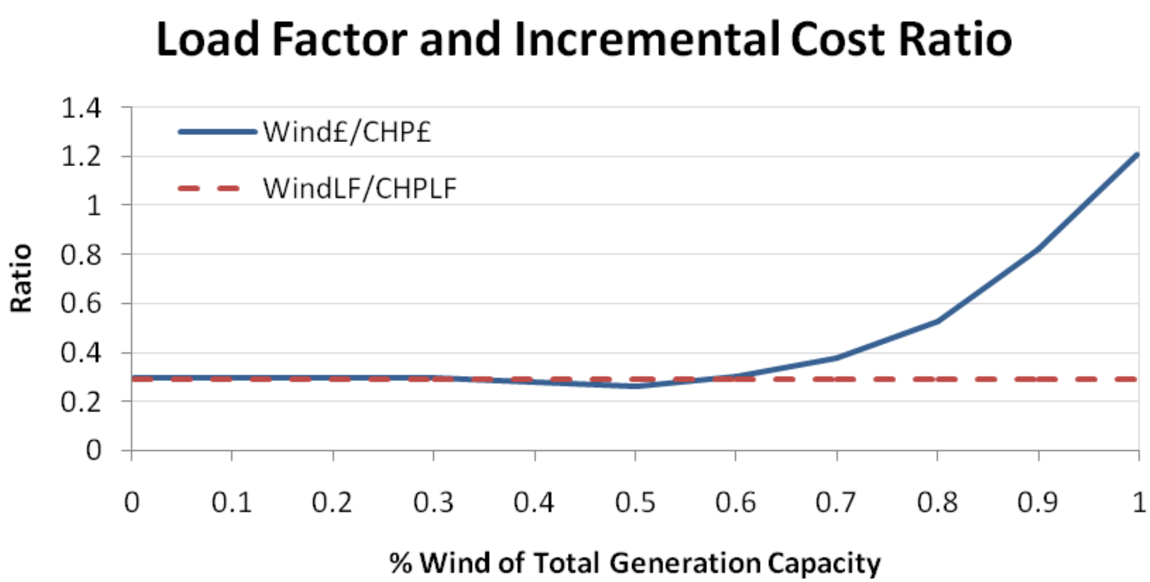
LRMC = £50 - £110/MWkm for 75km = £3750 - £8250/MW

Onshore Wind + CHP; Export; 2011



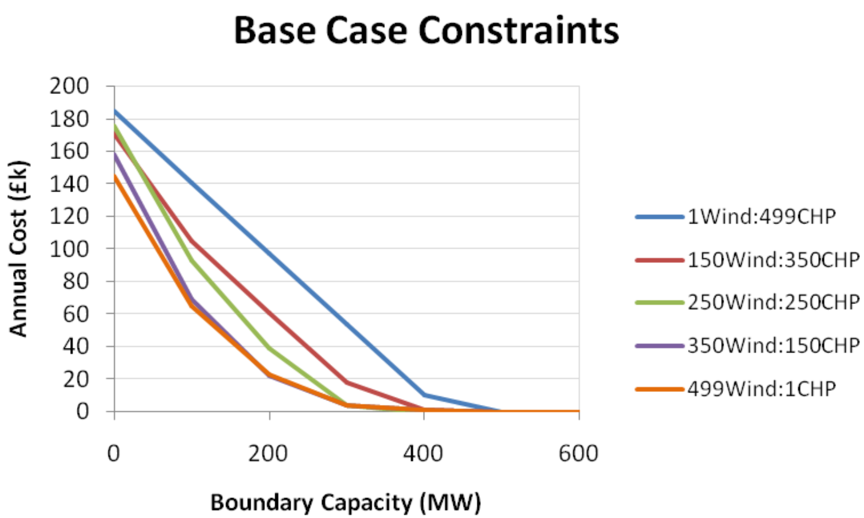
- Ideal = Wind LF/CHP LF
- Wind LF = 22%
- CHP LF = 75%

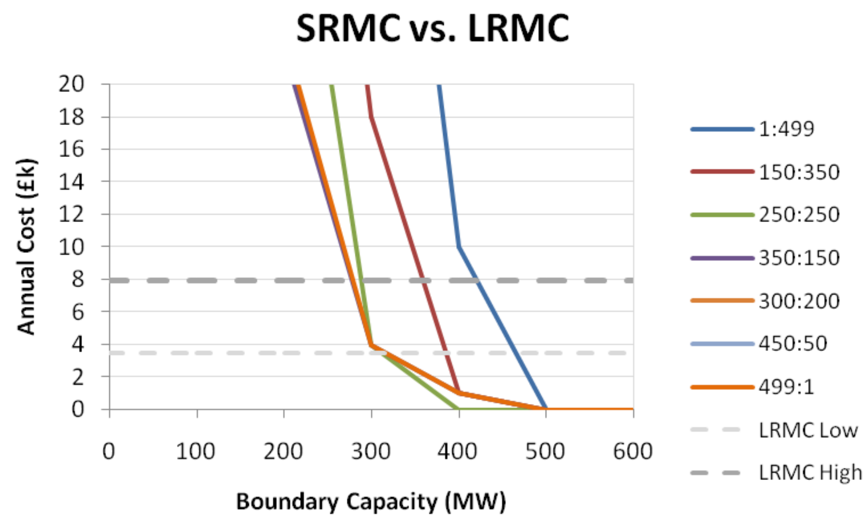
- At optimum boundary capacity

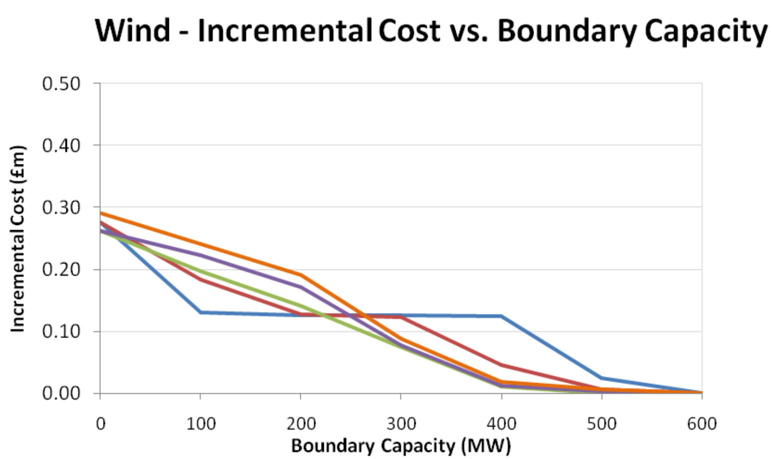


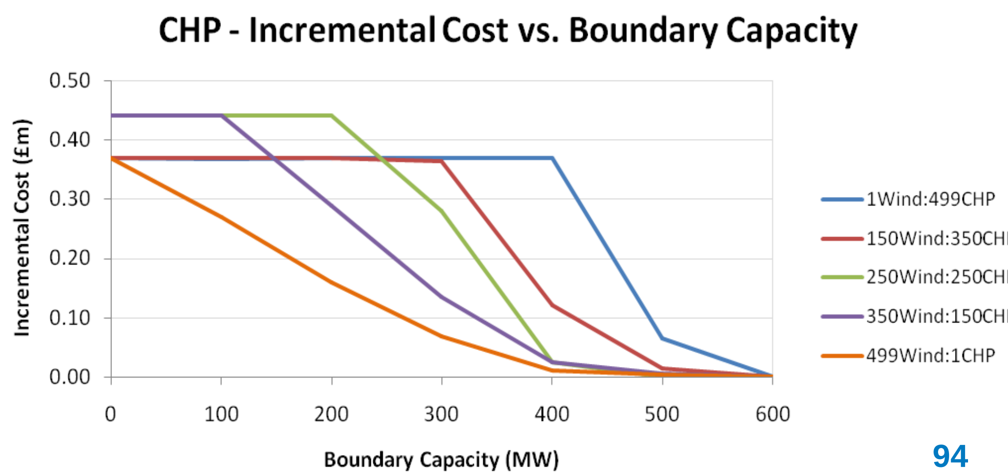
Wind Bid = -50 £/MWh; CHP Bid = 16.63 £/MWh

Onshore Wind + CHP; Export; 2020



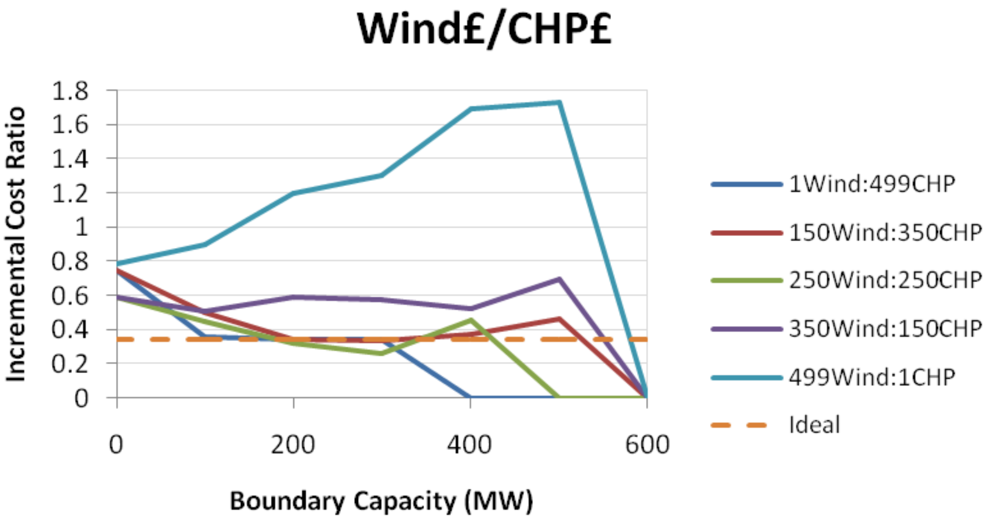






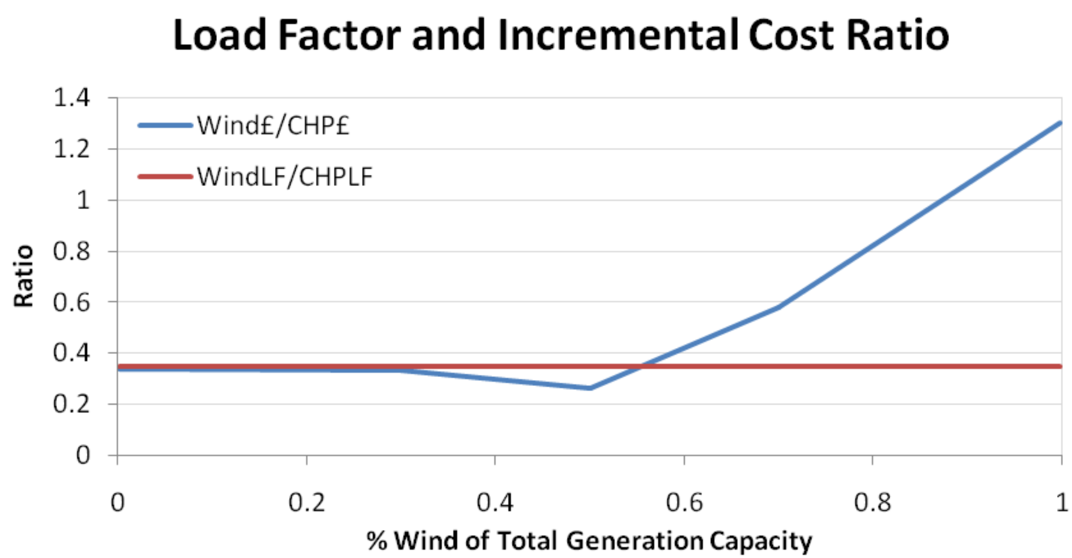
LRMC = £50 - £110/MWkm for 75km = £3750 - £8250/MW

Onshore Wind + CHP; Export; 2020



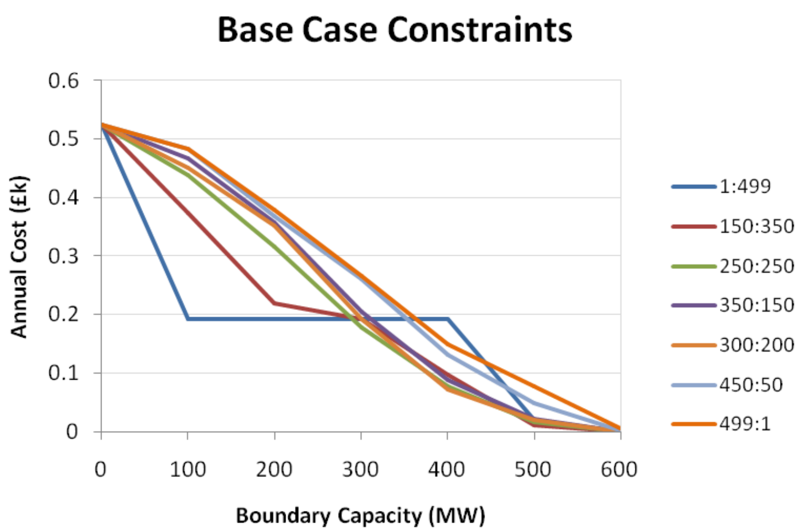
- Ideal = Wind LF/Coal LF
- Wind LF = 21%
- CHP LF = 75%

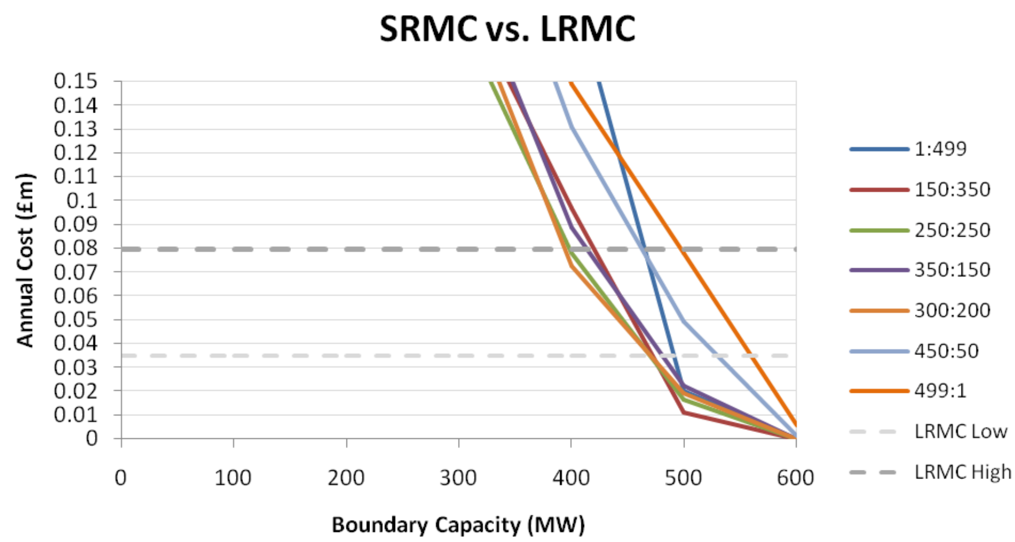
- At optimum boundary capacity

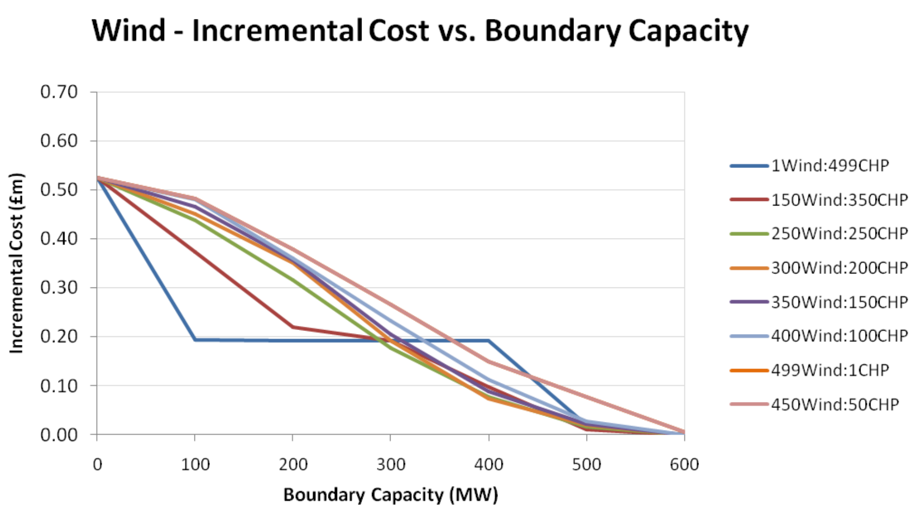


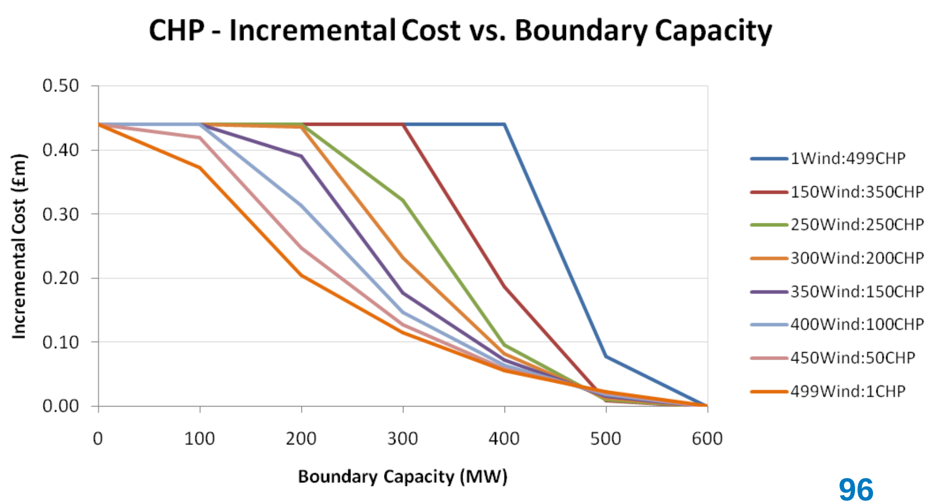
Wind Bid = -50 £/MWh; CHP Bid = 16.63 £/MWh

Offshore Wind + CHP; Export; 2011



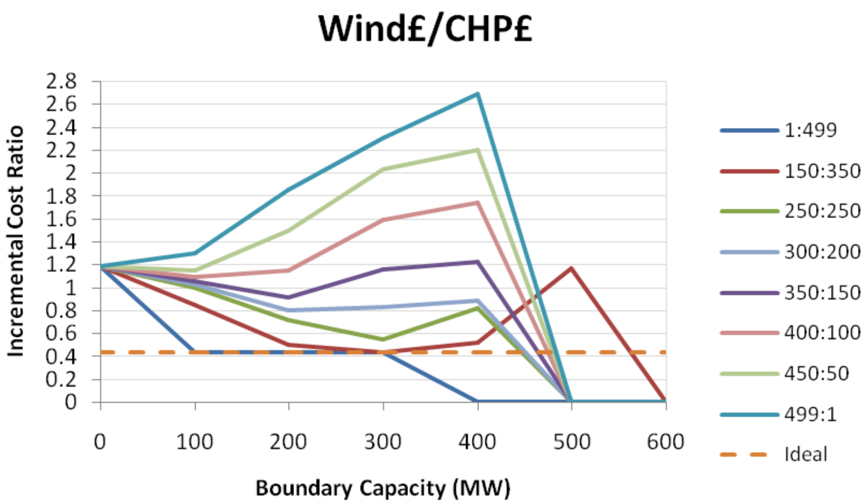






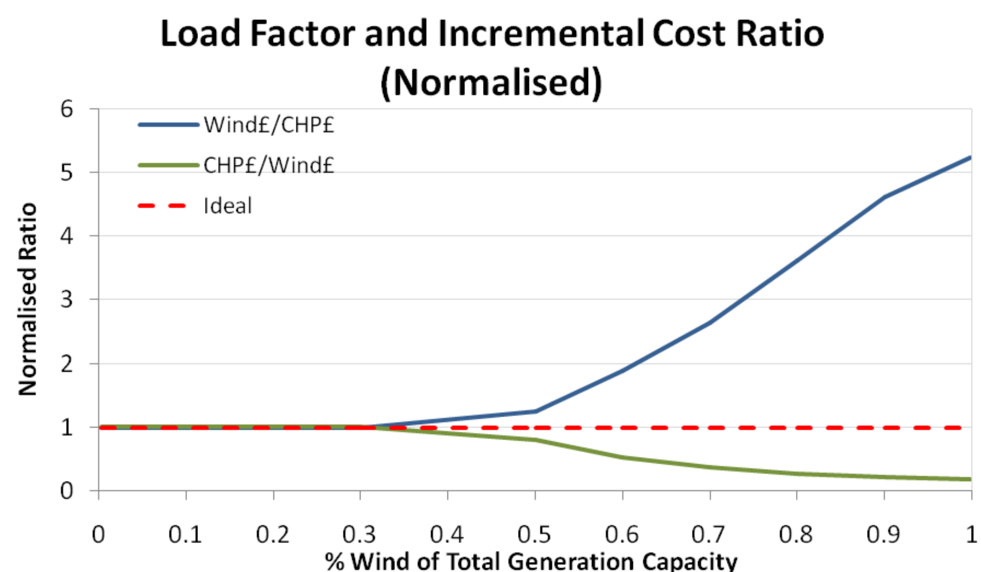
LRMC = £50 - £110/MWkm for 75km = £3750 - £8250/MW

Offshore Wind + CHP; Export; 2011



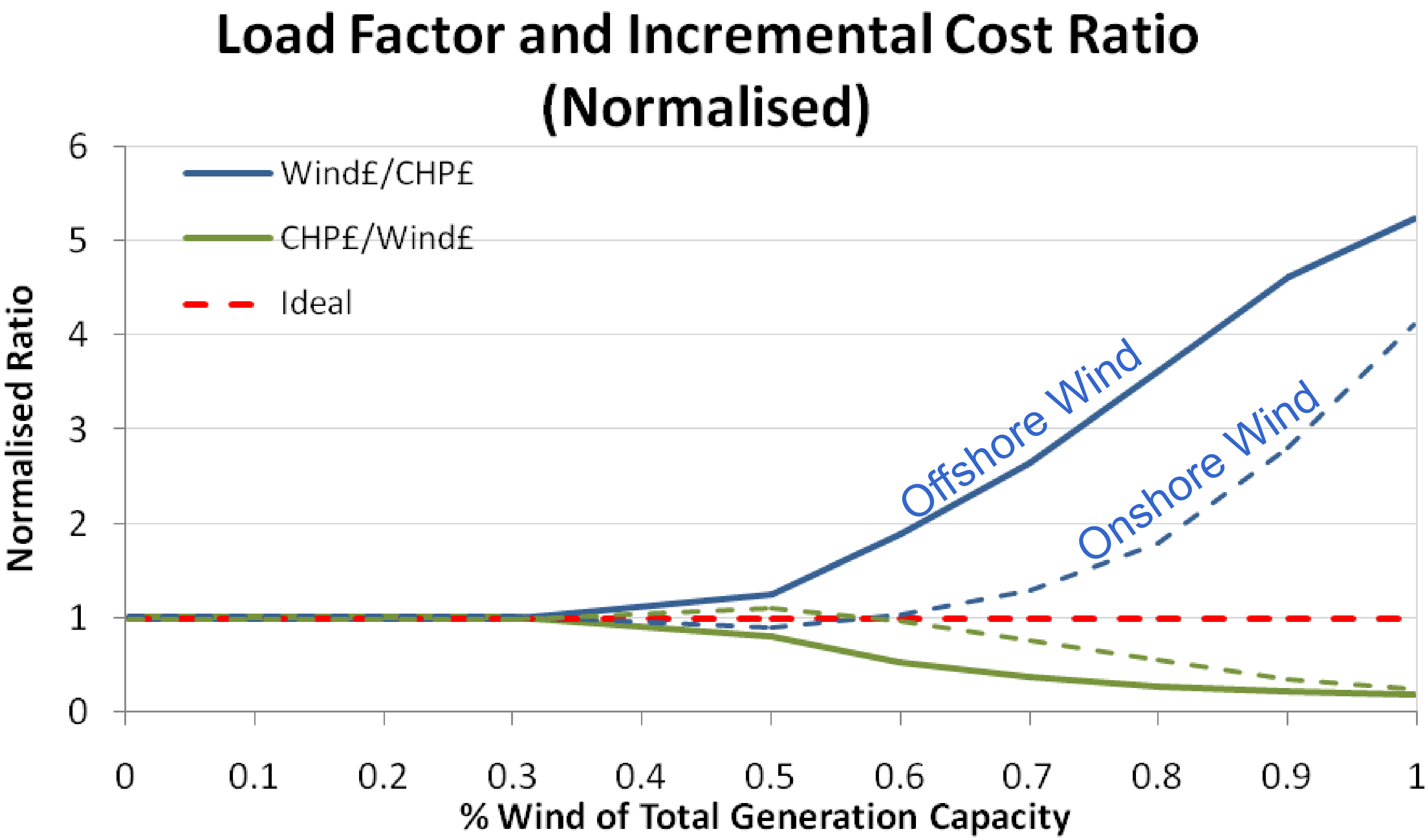
- Ideal = Wind LF/CHP LF
- Wind LF = 33%
- CHP LF = 75%

- At optimum boundary capacity



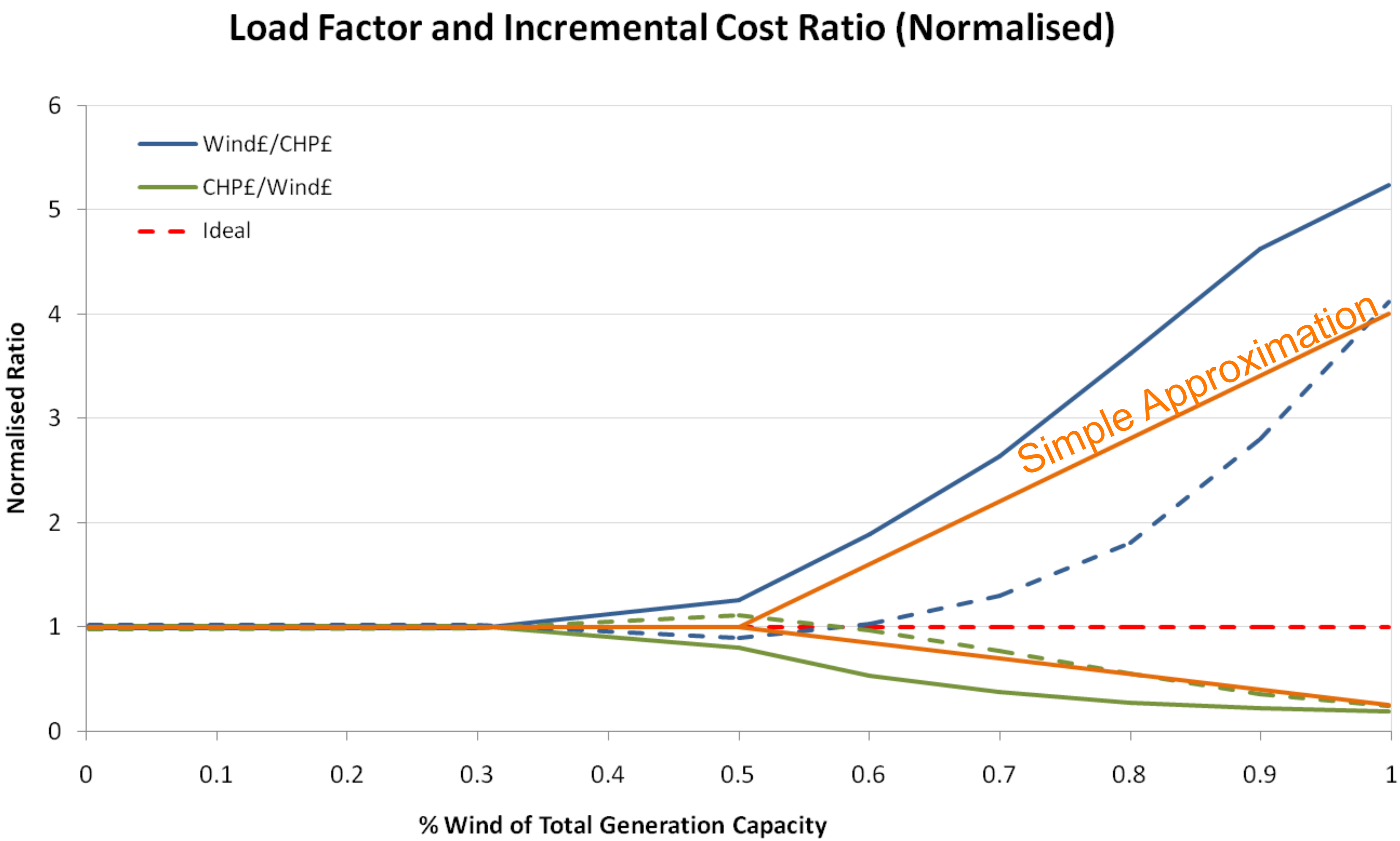
Wind Bid = -100 £/MWh; CHP Bid = 16.63 £/MWh

On vs. Offshore Wind + CHP; Export; 2011



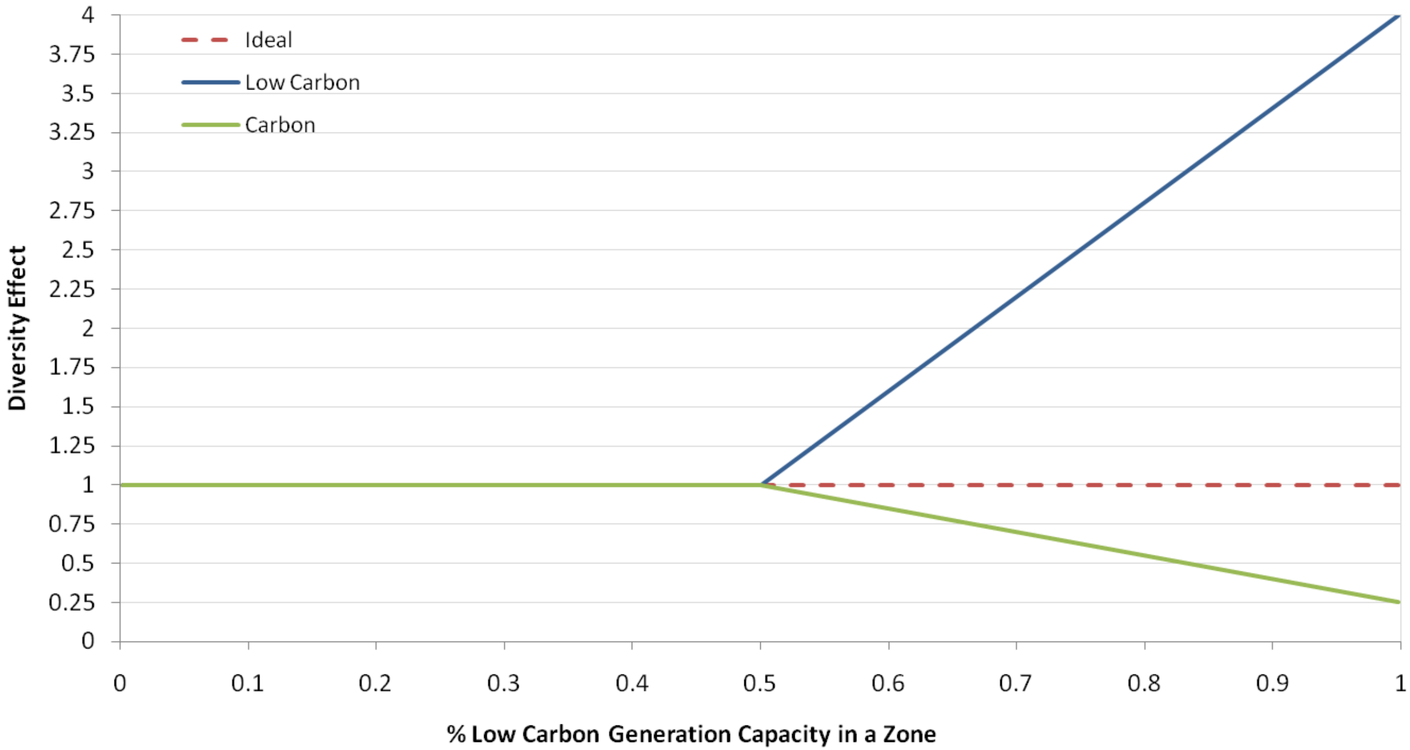
- Results normalised against Wind LF/ CHP LF

Proposed Relationship for Method 1 Use



Proposed Diversity Relationship for Method 1

- Results of analysis
- Used to attribute ‘year round’ zonal incremental km to shared or non-shared



Annex 3 – Proposer presentation

CMP268 Workgroup

Proposer's Presentation
2nd Feb 2017

Contents

Evidence previously provided to CMP268 Workgroup:

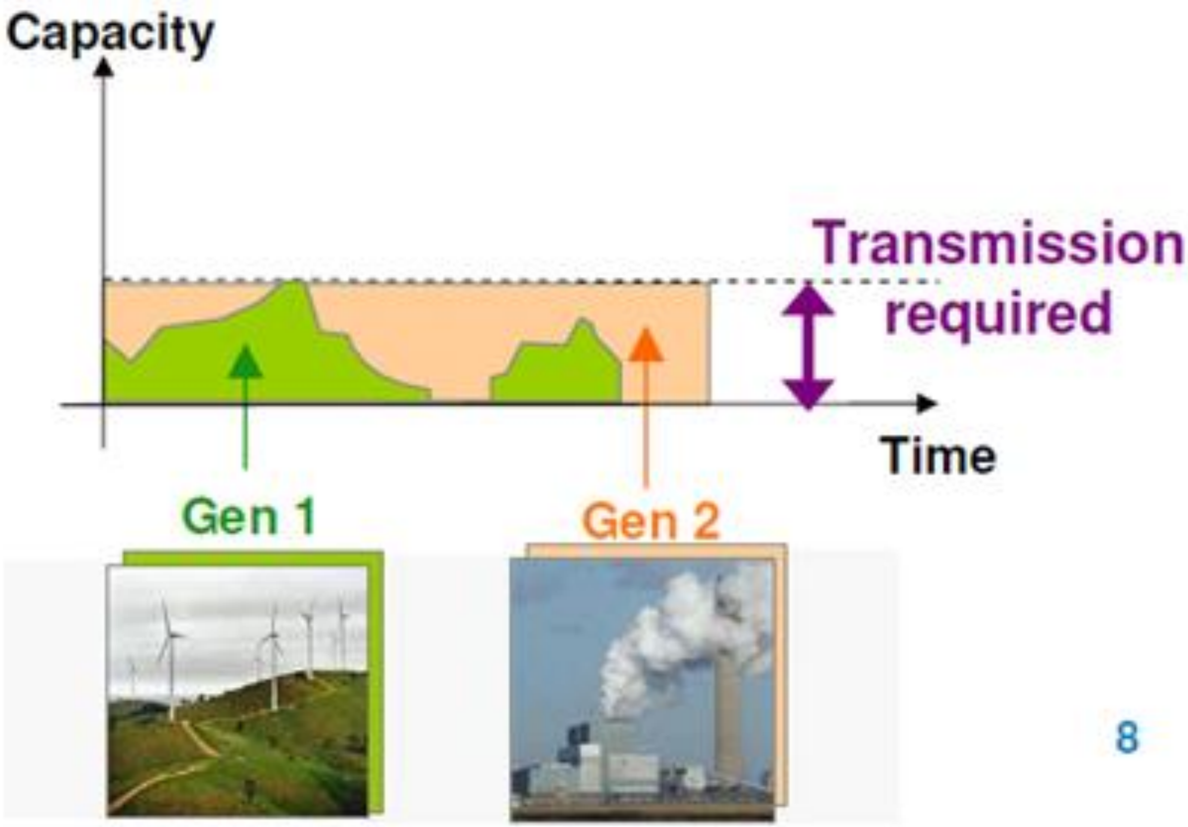
1. **Principles of sharing and cost reflectivity**
2. **CMP268 Defect and Proposal**
3. **Evidence – Cost Reflectivity**
4. **Empirical evidence – As expected**
5. **Impact – Distributional affect**
6. **Impact - Year Round crowding out Peak Security Price Signals**

1. Principles of sharing and cost reflectivity

CUSC say about cost reflectivity

"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."* (CUSC Section 14, paragraph 14.14.6) [emphasis added]

Principle of sharing – TransmiT WG1



“Not all users drive the same requirement for investment”

TransmiT – constraint cost is key

"Network capacity vs. future savings in operational costs"

CMP213 FMR said about sharing

“The [CMP213] Workgroup agreed that **<u>annual incremental constraint costs</u>** 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) [emphasis added]

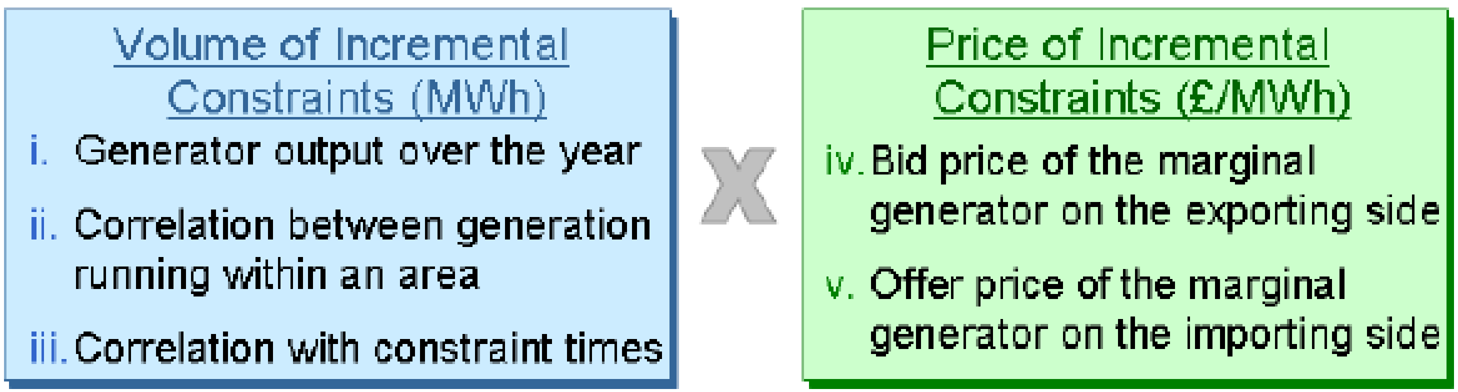


Figure 5 – Components that drive transmission constraint costs

For Conventional Carbon generators, these drivers of “annual incremental constraint cost” :

DO **<u>NOT</u>** CHANGE WITH INCREASED SHARE OF LOW CARBON GENERATION

Economic principles relate to CMP268

“*Conventional carbon generators will tend to avoid generating during periods when constraints are most likely…*

…and even if they are generating, during those periods, then they will tend to be relatively low cost for the System Operator to bid off, so provide a relatively low cost option for mitigating those constraints.”

This does not change when the penetration of low carbon increases.

2. CMP268 Defect and Proposal

CMP268 Defect

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

“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”.

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%.”

Definition of “Conventional Carbon”

		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

New framework introduced by CMP213

Before CMP213:

All generators pay 100% of TEC

Introduced by CMP213:

Peak Security Background
- Class of “Conventional”
- Class of “Intermittent”

Year Round Background
- ALF

Diversity calculation
- Class of “Carbon”
- Class of “Low Carbon”

Year Round Not Shared
- Intermittent Low Carbon
- Conventional Low Carbon
- *Intermittent Carbon*
- Conventional Carbon

Sharing solution

For Conventional Carbon: What happens already, just keeps happening

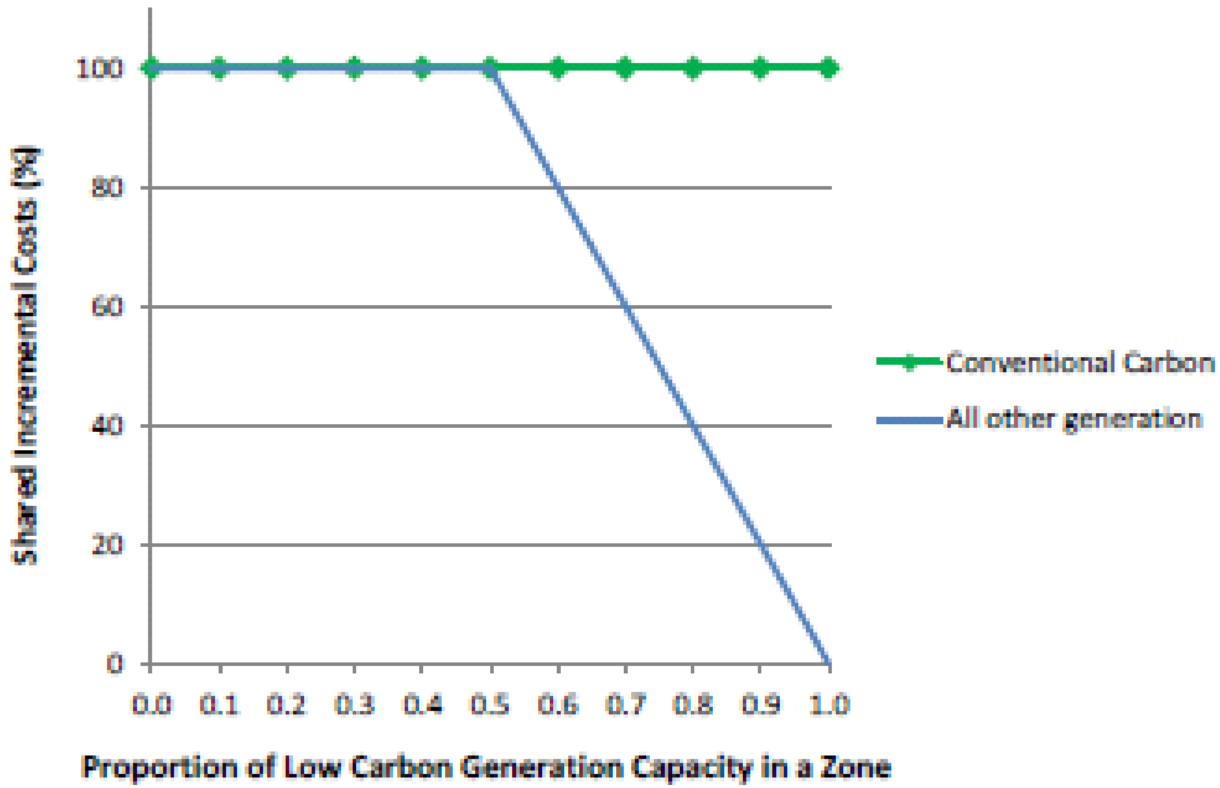


Figure 3: Proposed change - Modified Figure 1

The defect is only with the tariff formula

Adjusted tariff formula: "Conventional Generator – Carbon"

Wider Tariff = Peak Security element + (Year Round Shared Element × Annual Load Factor) + (Year Round Not shared element × Annual Load Factor) + Residual element

Unchanged tariff formula: "Conventional Generator – Low Carbon"

Wider Tariff = Peak Security element + (Year Round Shared Element × Annual Load Factor) + Year Round Not shared element + Residual element

Unchanged tariff formula: "Intermittent"

Wider Tariff = (Year Round Shared Element × Annual Load Factor) + Year Round Not shared element + Residual element

3. Evidence – Cost Reflectivity

ELSI consistent with "theoretical perfect relationship"

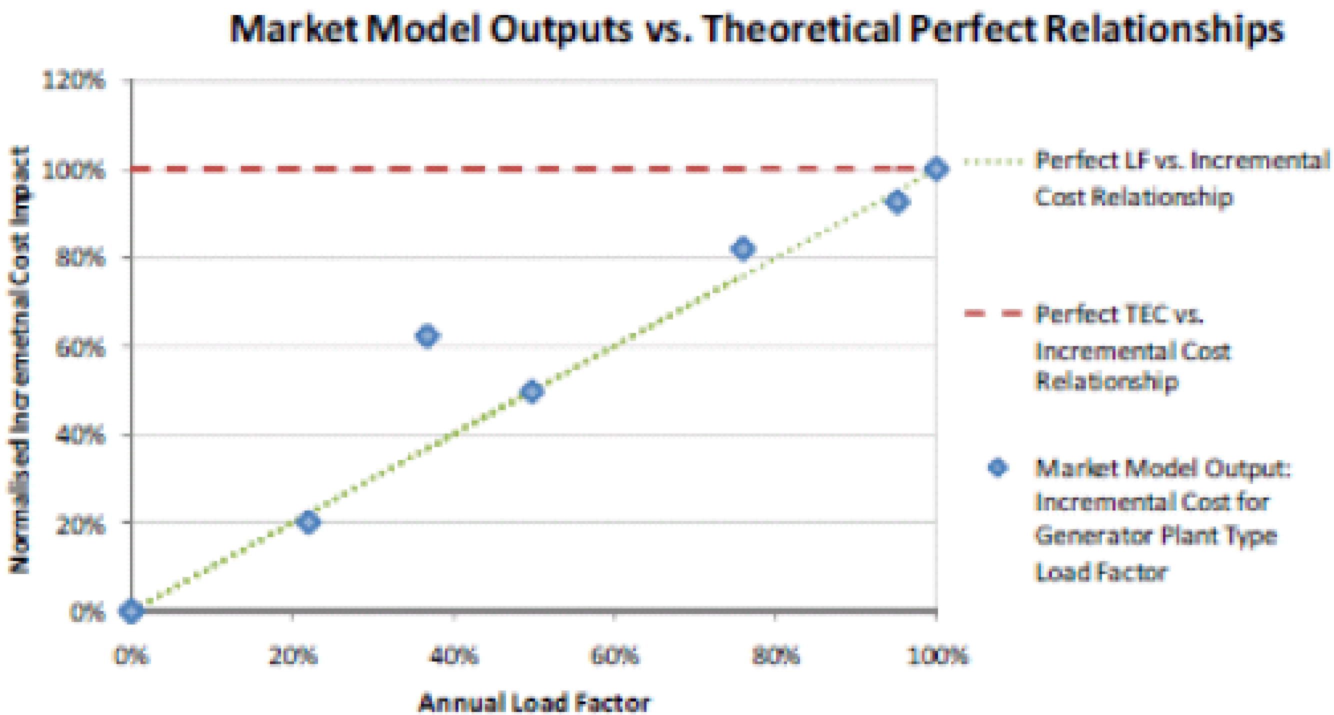


Figure 1 – Market Model Outputs vs. Theoretical Perfect Relationships

Circumstances where sharing is reduced

"…for areas of the transmission system with insufficient generation plant diversity… 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]

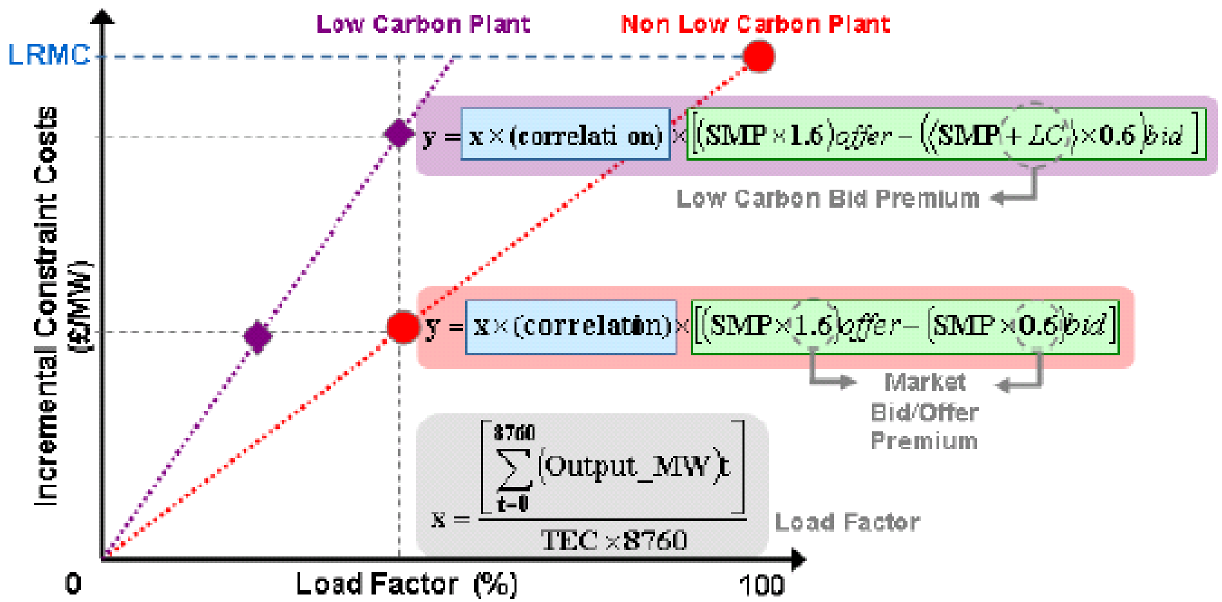


Figure 21 – Combined effect of price and load factor on constraint costs

CMP213 Final Workgroup Report Volume 2 Annex

Evidence – Simplified two node model

"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**." (Final CUSC Modification Report Volume 1, 4.38)

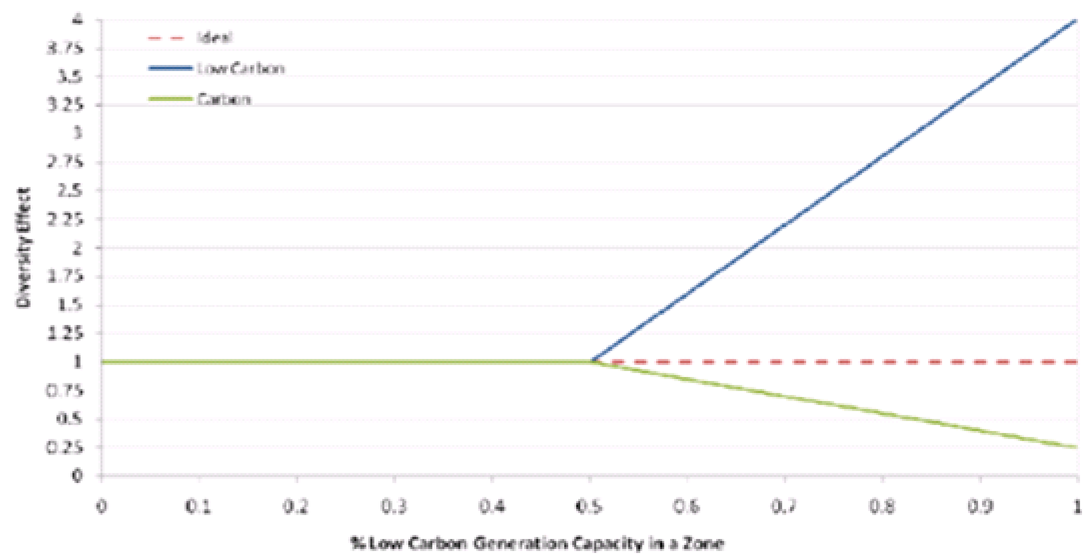


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

Evidence – ELSI model and reduced sharing

ELSI analysis in the CMP213 FMR supported the CMP268 position that Conventional Carbon remains close to the ideal 45 degree line (circled in green). By contrast, it is only the Low Carbon generation which has moved off the 45 degree line (circled in red).

[Note the coloured highlights have been added]

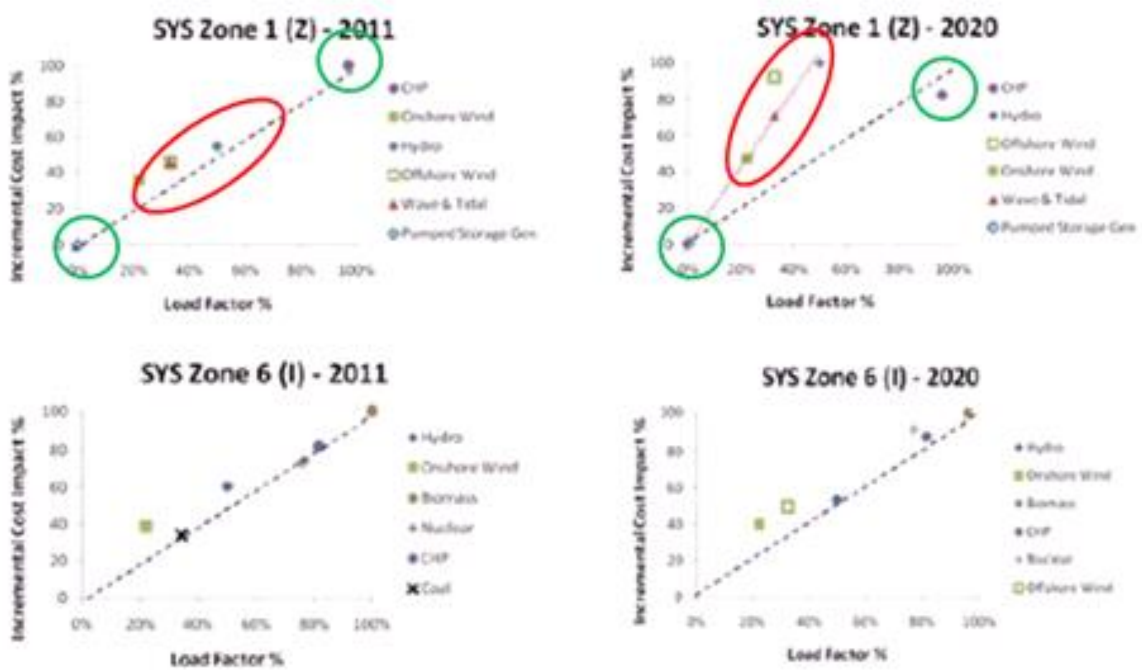
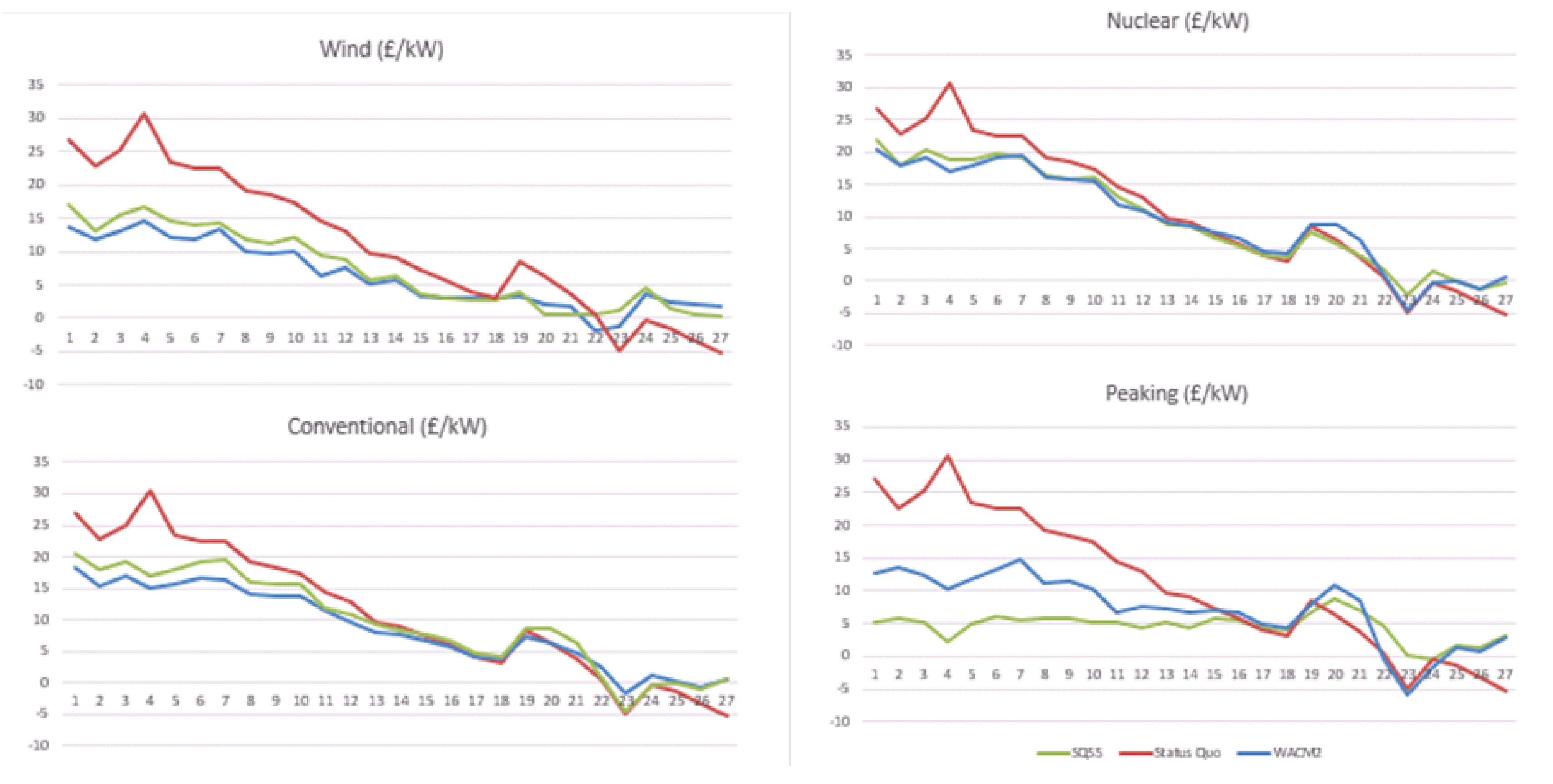


Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

Evidence Cost reflectivity compared with SQSS - P E Baker



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

Evidence - Alternative modelling of cost reflectivity (two node model)

"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)

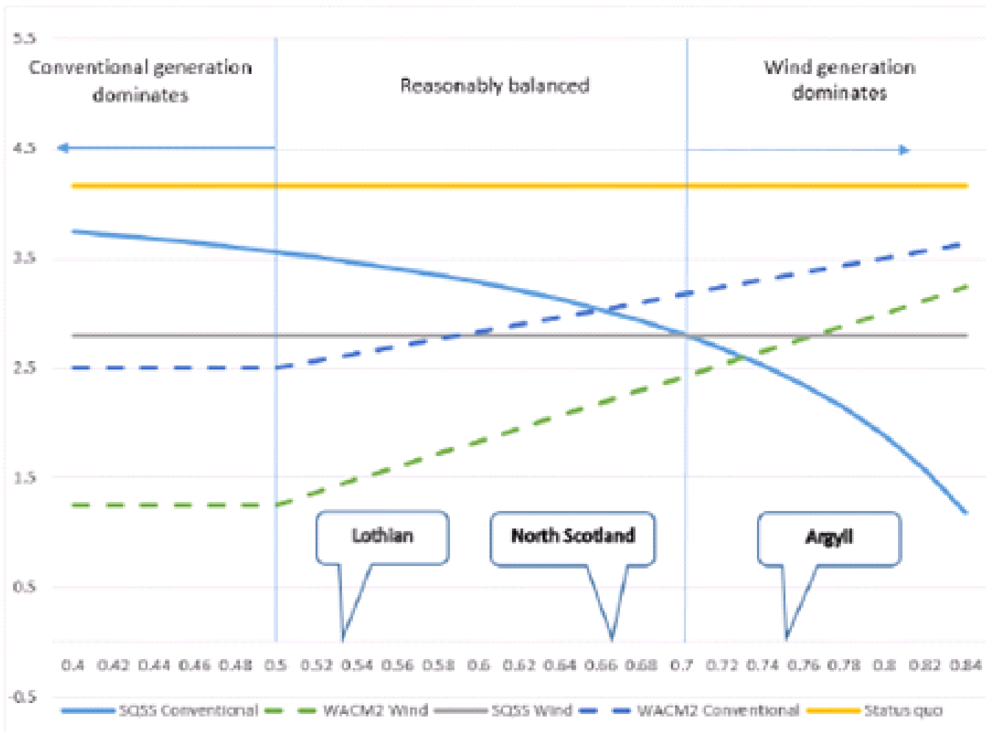
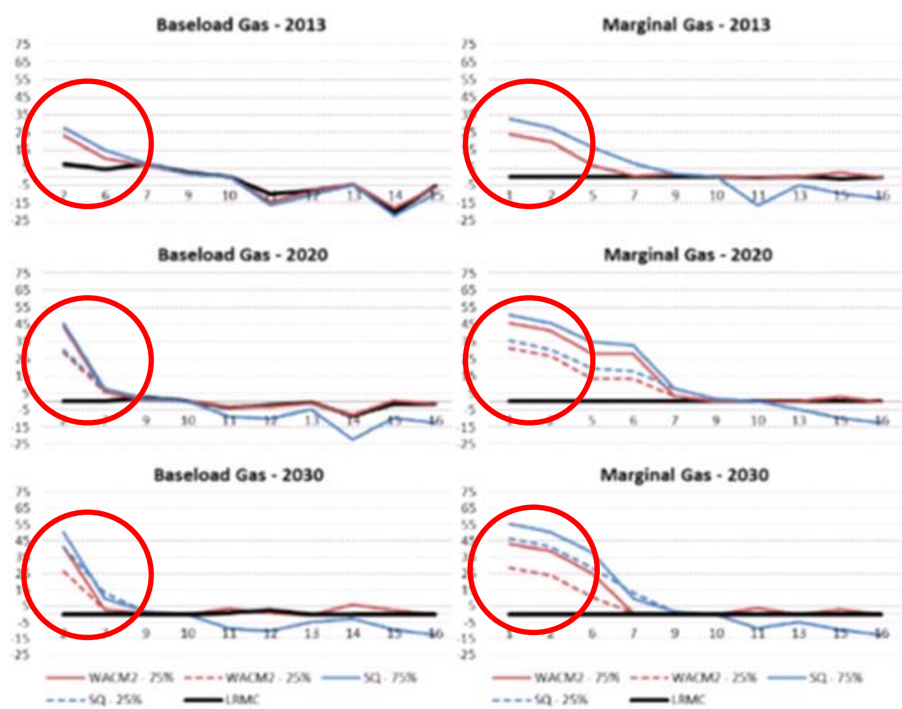


Figure 4. Variation of SQSS costs (£/kW) and WACM2 & Status Quo charges (£/kW) with sharing

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

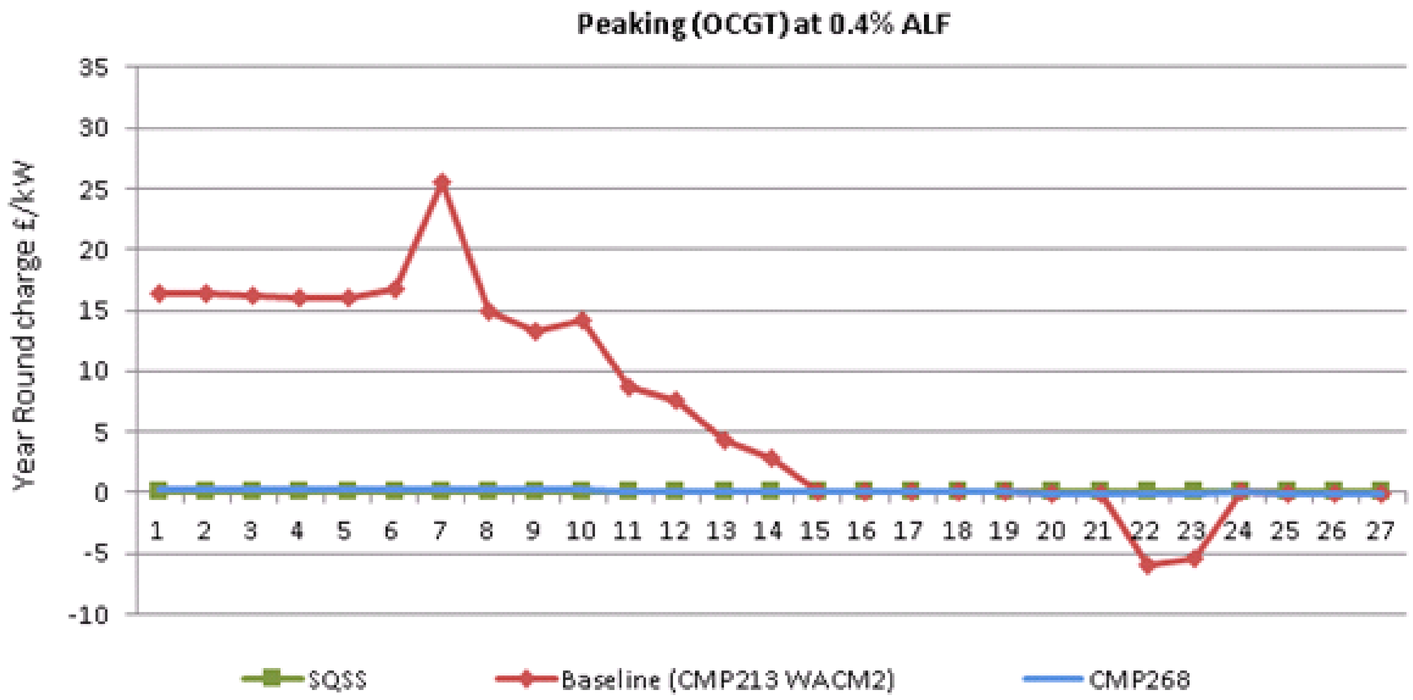
"As noted above, LRMCs for peaking gas-fired generators are low in all zones, often close to zero. Both the WACM 2 and status quo methodologies charge this type of generator tariffs well-above LRMC in the Scottish zones in 2013, 2020 and 2030." (NERA/ICL 5.2.2.) [coloured highlights added]

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

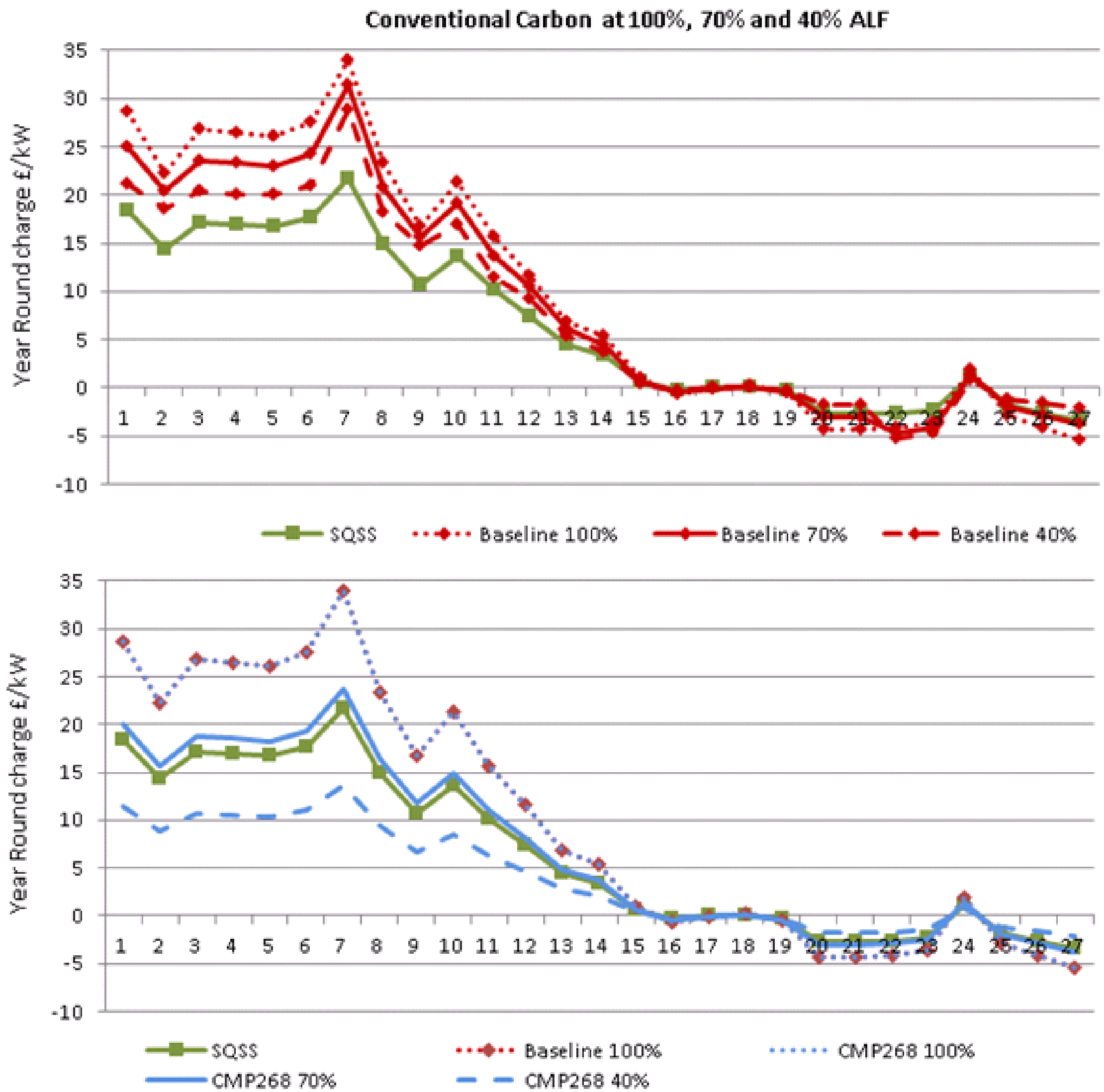


Source: NERA/Imperial

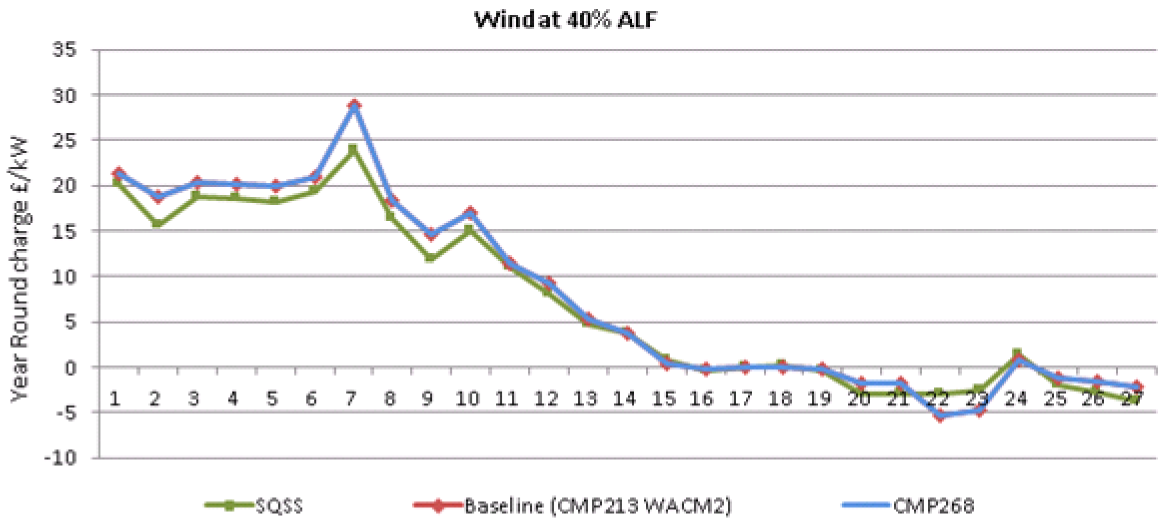
New analysis: Baseline vs. CMP268 vs. SQSS

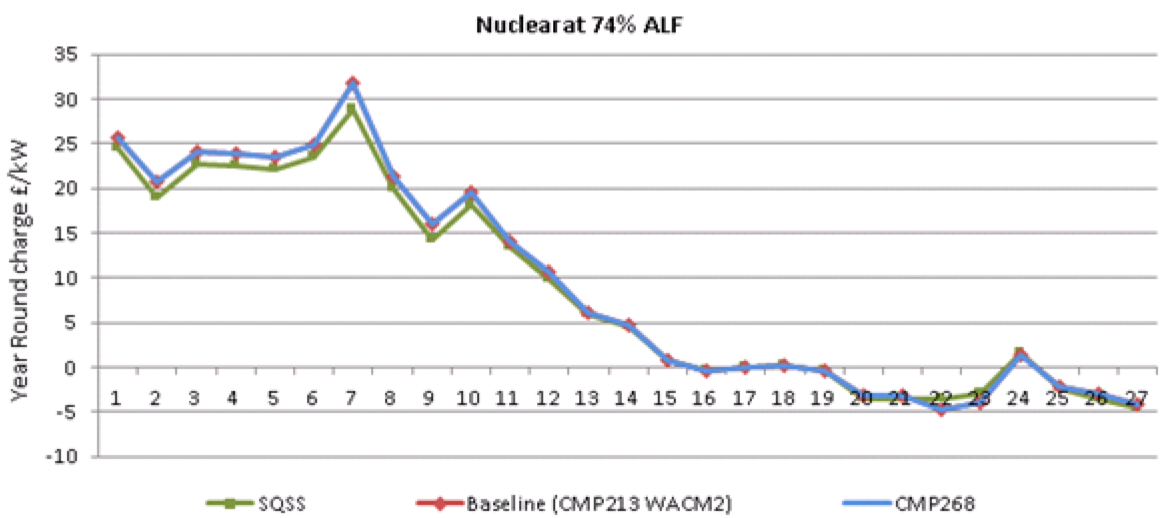


New analysis: Baseline vs. CMP268 vs. SQSS



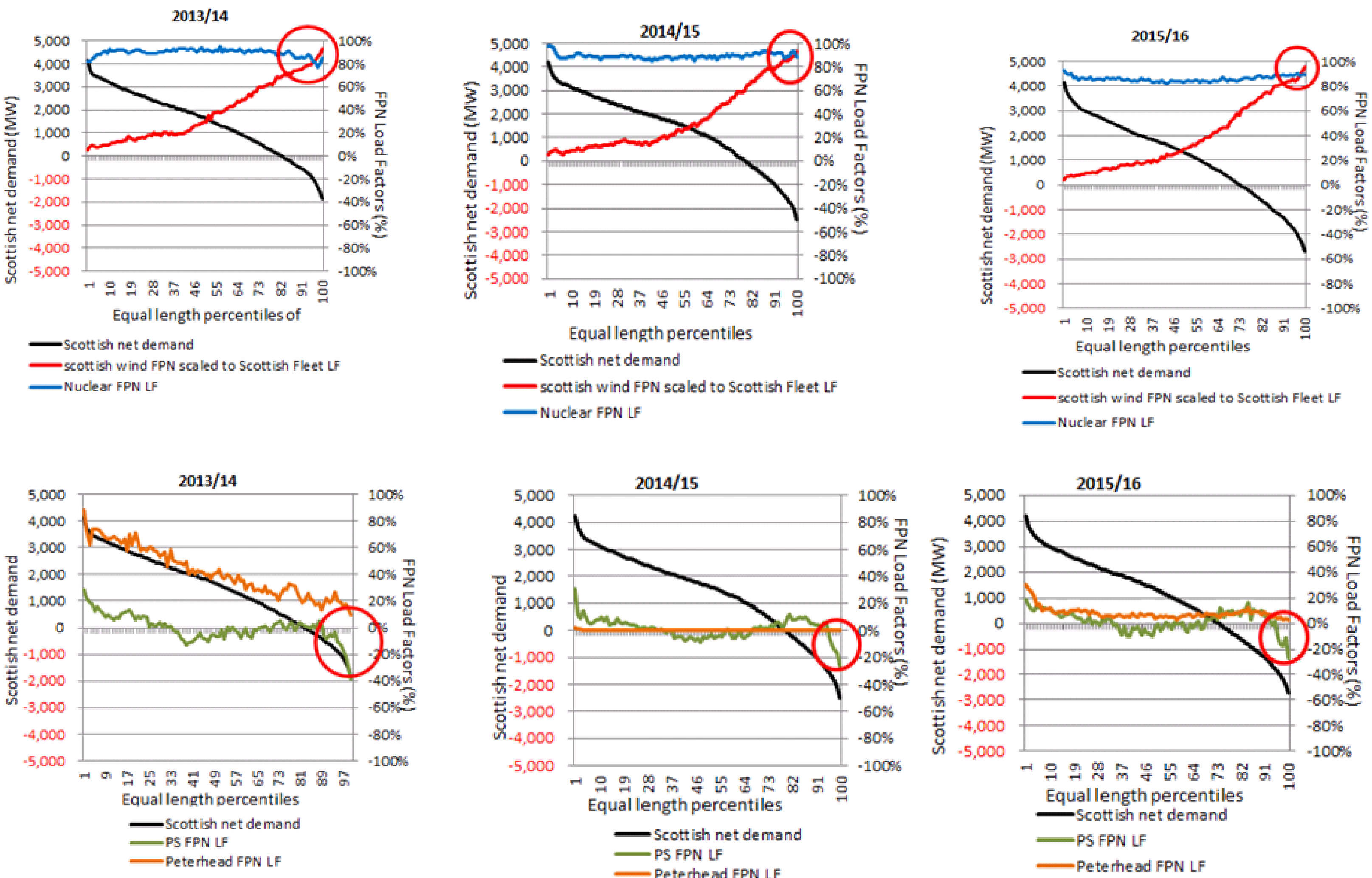
New analysis: Baseline vs. CMP268 vs. SQSS



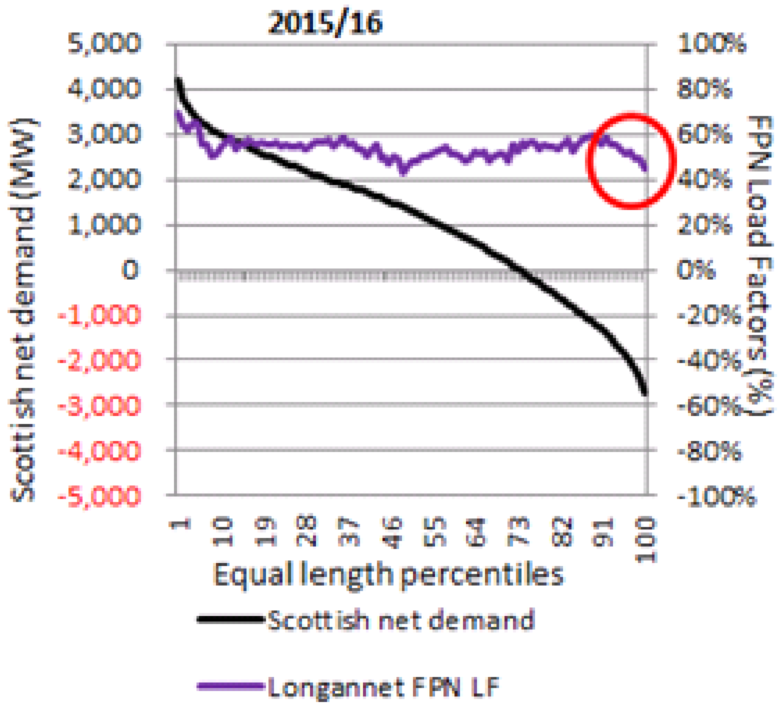


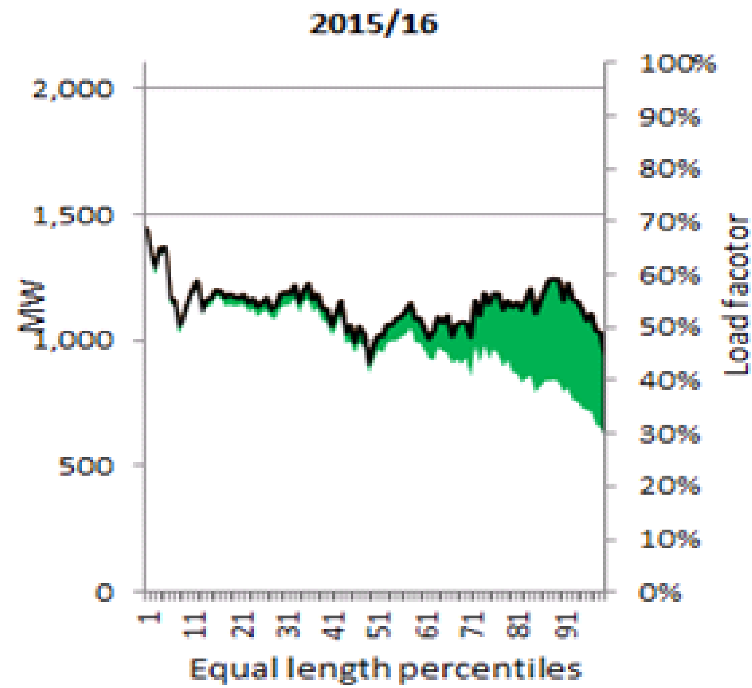
4. Empirical evidence – AS EXPECTED

New Analysis: Correlation with periods of constraint (Low Carbon vs. Carbon) – AS EXPECTED

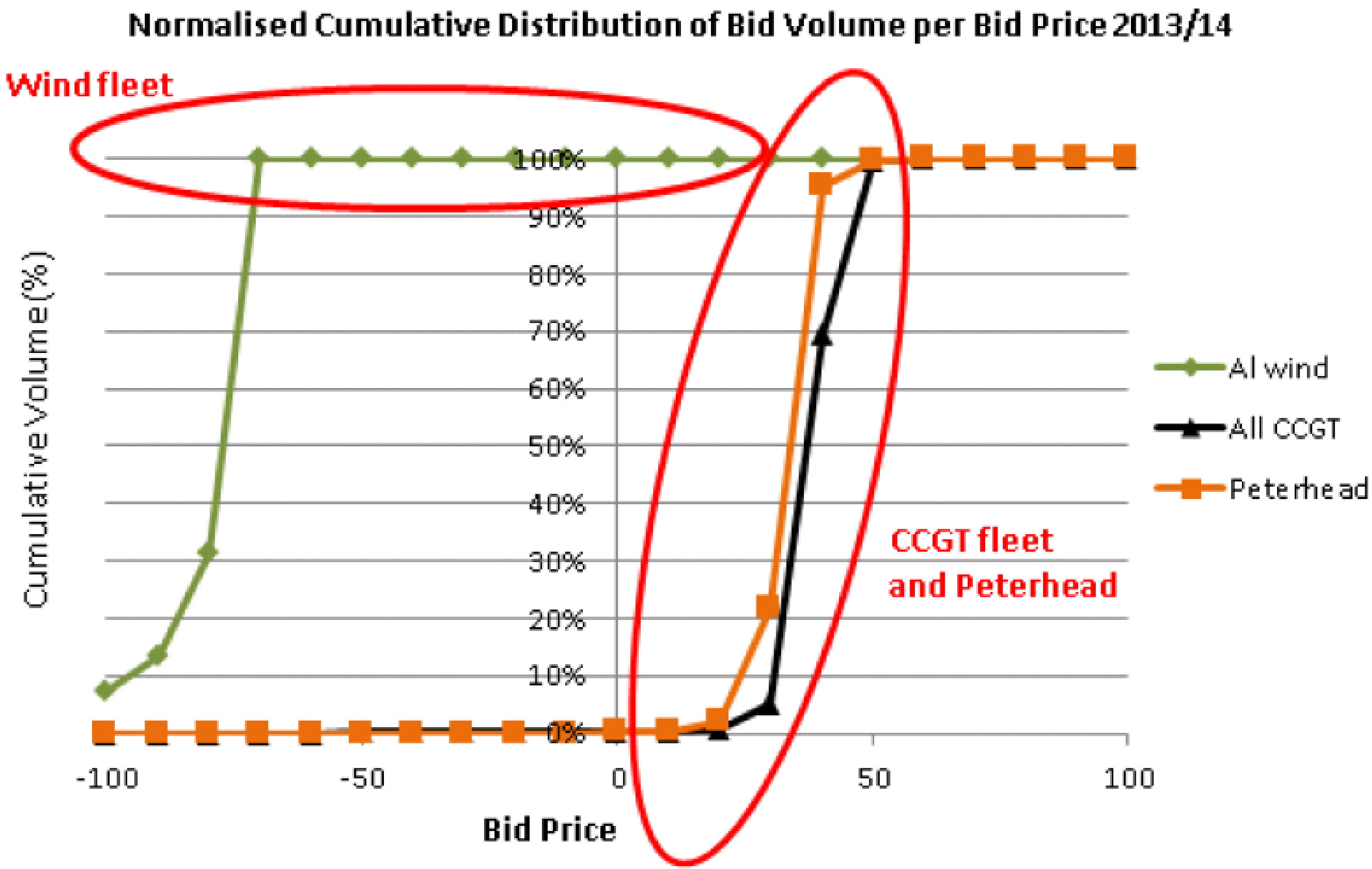


New Analysis: Longannet bid price characteristics – <u>AS EXPECTED</u>



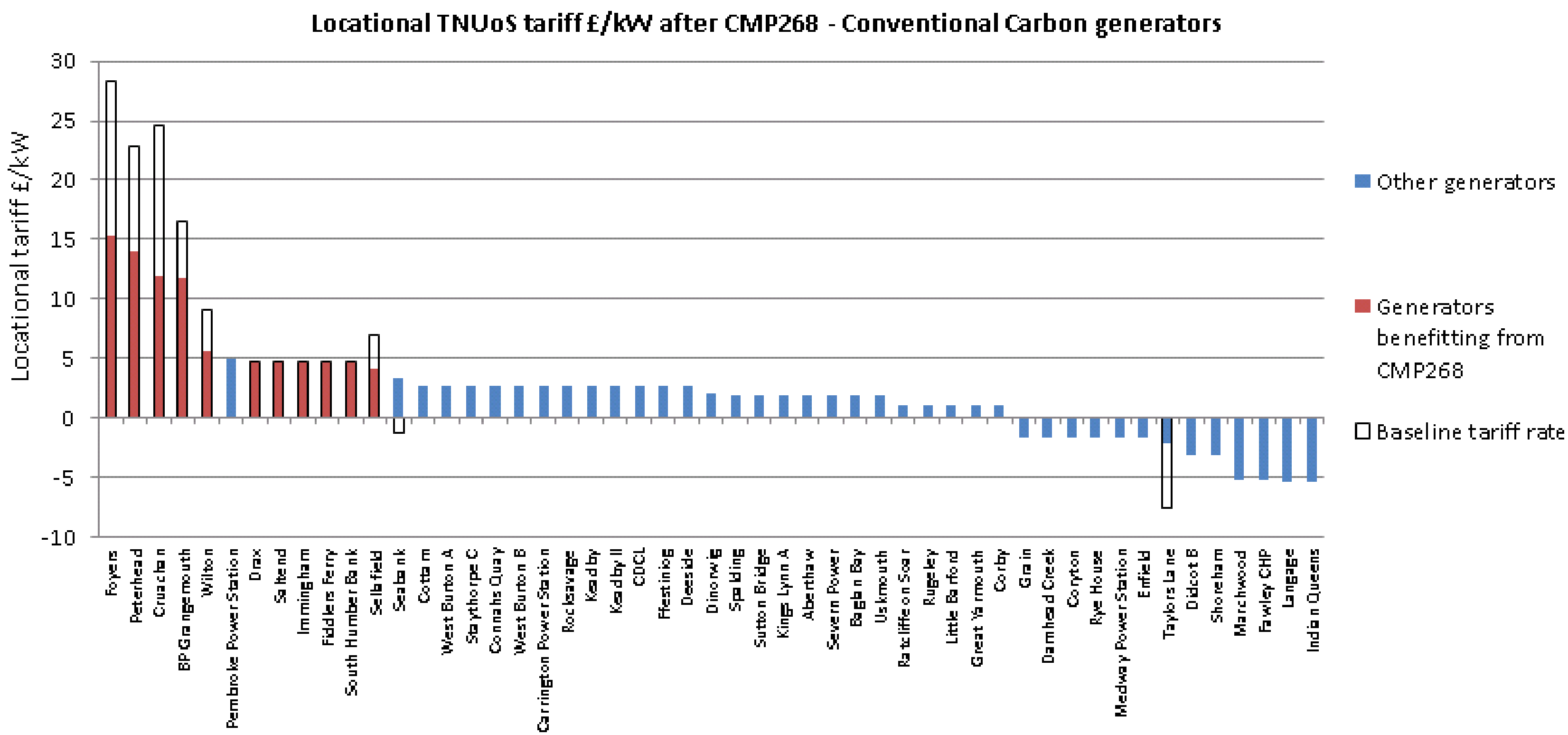


Bid prices are different – AS EXPECTED



5. Impact – Distributional affect

Affected Conventional Carbon generators still pay among the most expensive TNUoS charges

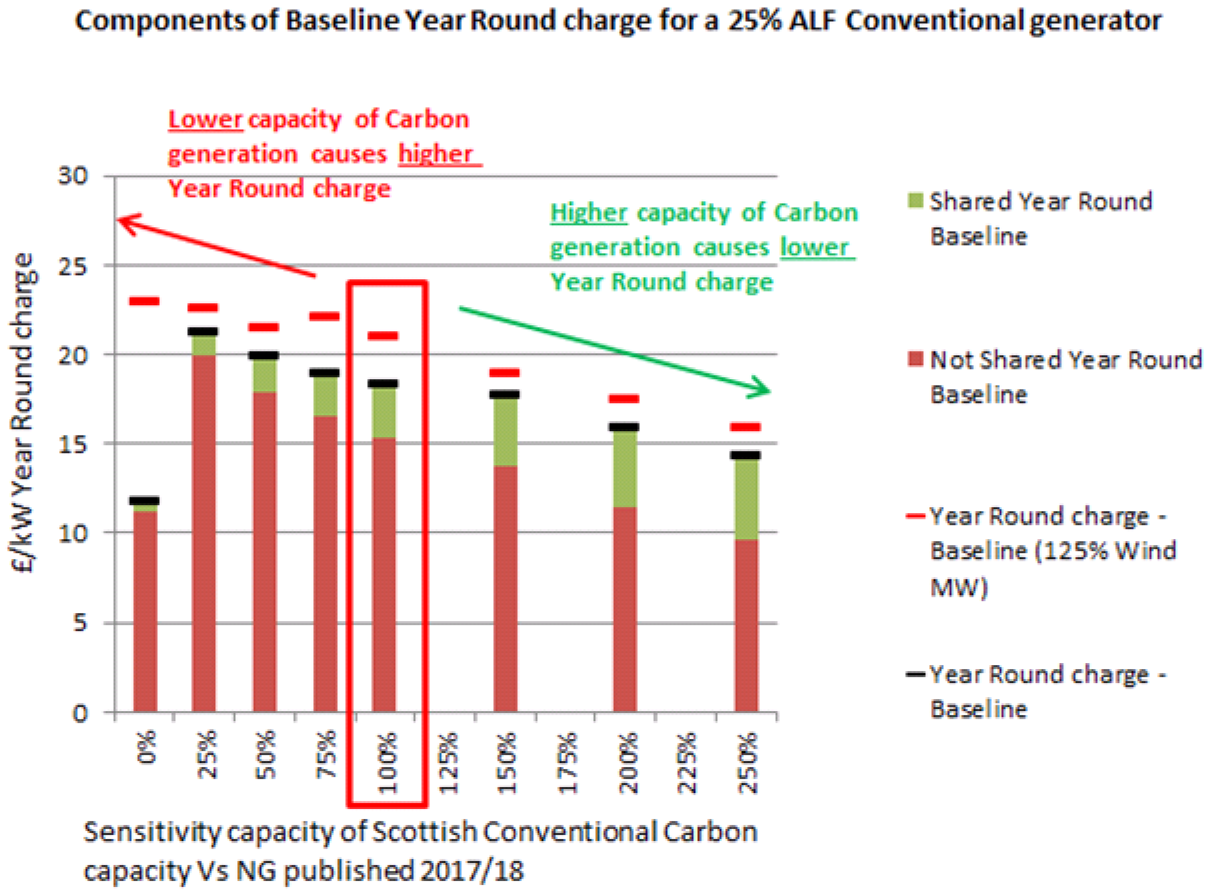


6. Impact - Year Round crowding out Peak Security Price Signals

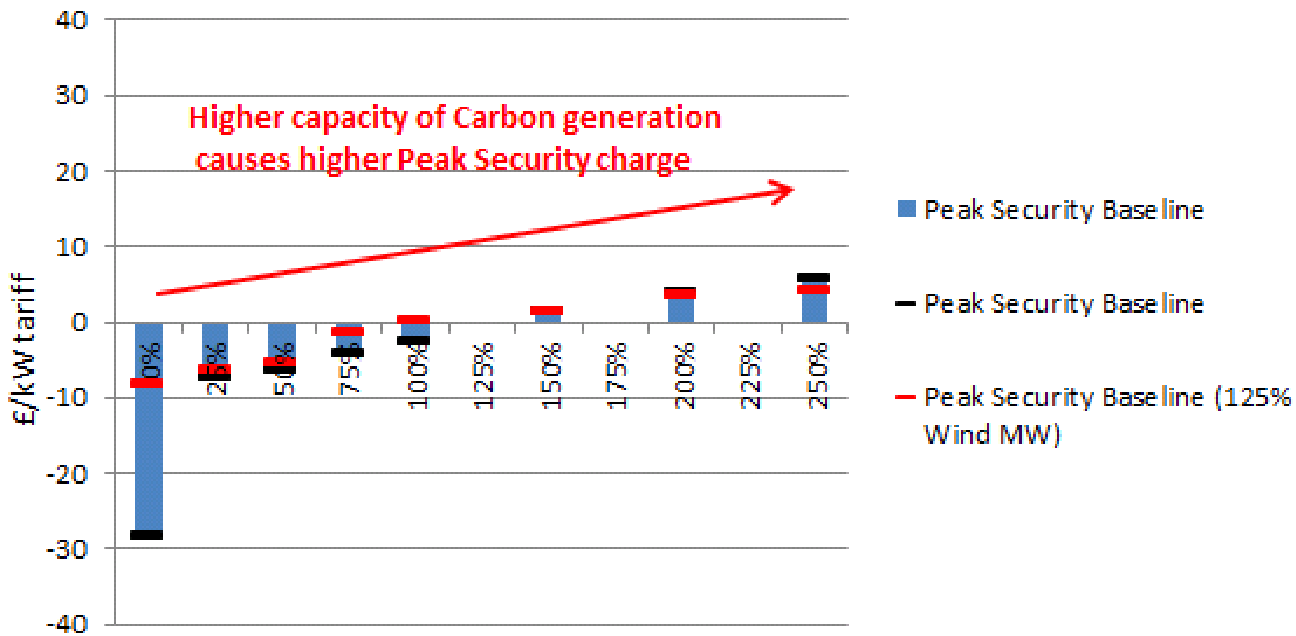
Evidence from Poyry for Centrica

“…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]

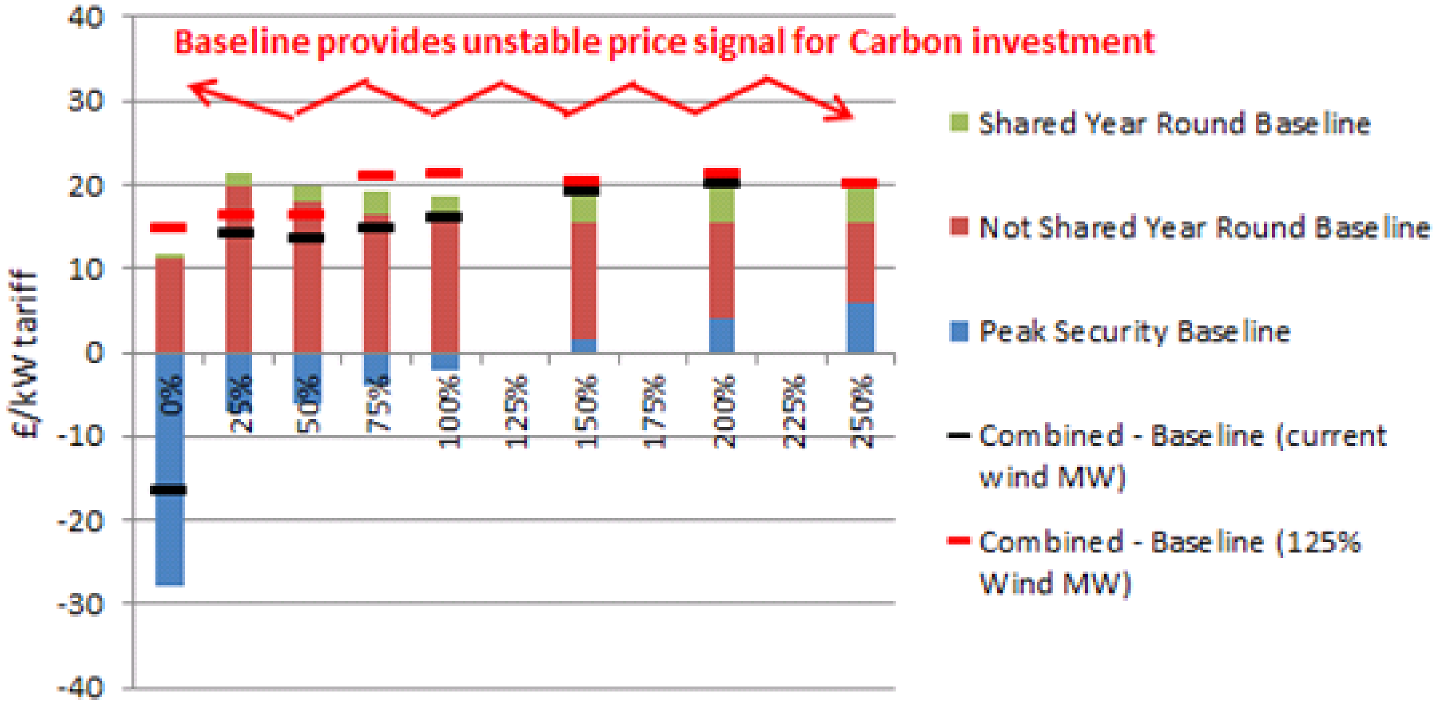
New analysis: Baseline impact on Year Round price signals



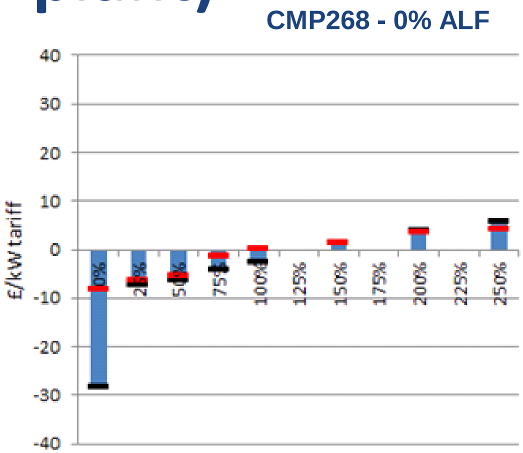
New analysis: Baseline impact on Peak Security price signals

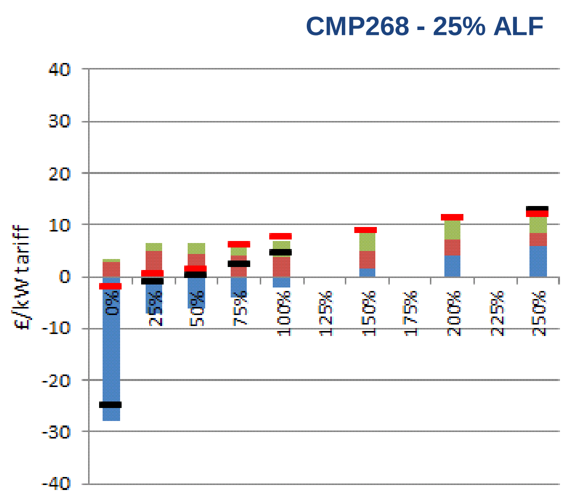


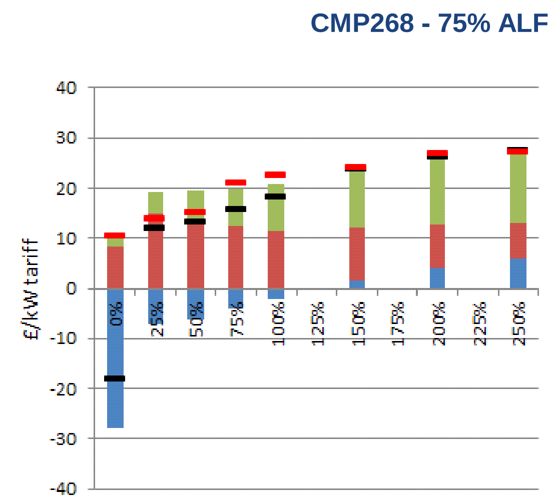
New analysis: Baseline impact on combined price signals



New analysis: Baseline impact on combined price signals (sensitivity of change in Conventional Carbon plant)







Better price signal for different plant

- **For 0% ALF generator** – Peak Security Price signal dominates
- **For 25% ALF generator** – balance of price signals
- **For 75% ALF generator** – Year Round price signal dominates

Annex 4 – RWE Cost reflectivity paper

This paper was submitted to the Workgroup to consider and is attached.

CMP268 – Initial thoughts on the basis of sharing year round locational tariffs in relation to year round generation transmission tariffs.

DRAFT

Executive Summary

i. This paper considers the basis of sharing of year round generation transmission tariffs under the charging methodology in the context of CUSC Modification proposal CMP268. The sharing methodology in the CUSC allocates plant in a zone according to the low carbon/carbon categories based on historic analysis and determines the level of "diversity" in a generation zone. This forms the basis of the allocation of MWkm into shared or not-shared year round locational tariffs. For users the shared component is paid by generators according transmission capacity and annual load factor (ALF); not-shared tariffs are paid according to transmission capacity.

ii. CMP268 seeks to relieve "conventional generation" from the not-shared component of the locational year round tariff by applying the ALF to the generation capacity. CMP268 justifies the relief in relation to the contribution of "conventional generation" to the cost constraints irrespective of the proportion of low carbon plant.

iii. CMP268 raises a number of issues regarding sharing including the nature of the carbon/low carbon split, the cost of constraints and the drivers of transmission investment in relation to the application of not-shared tariffs to conventional plant. However, CMP268 may misunderstand the nature of the ALF in the sharing methodology. The ALF simply represents the means by which the shared component of the tariff is shared.

----

1. Introduction

1.1. CUSC Modification Proposal 268 (CMP268) seeks to exclude "conventional generation" from the not-shared component of the GB year round transmission charges. This paper provides initial thoughts on the issues raised under CMP268. Section 2 provides an overview of derivation of year round generation charges in the Transport Model, Section 3 reviews the sharing methodology, Section 4 discusses the basis of sharing in the methodology, Section 5 considers sharing in the context of the CMP268 proposal and Section 6 concludes.

1.2. These are initial thoughts on the potential issues associated with CMP268 and the cost reflectivity of locational year round transmission tariffs for the purpose of discussion at the CMP268 Working Group.

2. Locational Year Round charges in the Transport Model

2.1. The principles establishing the basis for setting GB electricity transmission tariffs are set out in Section 14 of the Connection and Use of System Code (CUSC). Tariffs are derived from a DC load flow model based on the incremental costs of investment for each node on the transmission system measured in MWkm (the Transport Model).

2.2. Certain assumptions underpin the Transport Model with regard to the generation used for each background. In particular, generation capacity is adjusted for a "peak security" and “year round” backgrounds. These are derived from the Security Standard[1] and are set out below

Table 1: CUSC[2] Scaling Factors

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

2.3. In relation to the scaling factors, the CUSC states that the :

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

2.4. The Security Standard characterises the scaling arrangements for the year round background under “economy planned transfer conditions”[3] as follows:

“Appendix E Modelling of Economy Planned Transfer

E.1 For the determination of Economy planned transfer conditions plant is categorised in three groups:

E.1.1 non-contributory generation. This plant, such as OCGTs, does not form part of the generation background

E.1.2 directly scaled plant. The output of plant in this category is determined by a fixed scaling factor, described in E.3

E.1.3 variably scaled plant. The output of plant in this category is uniformly scaled by a variable factor that is calculated to ensure that generation and demand balance. This is described in E.5.

E.2 The NETS SO will from time-to-time review, consult on, and publish the categorisation of plant.

[1] National Electricity Transmission “System Security and Quality of Supply Standards”, at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/System-Security-and-Quality-of-Supply-Standards/

[2] CUSC Section 14.15.7

[3] The Peak Security background scaling factors in the Security Standard are included in Annex A for reference

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 system".

2.5. For the purpose of charging the CUSC describes the generating plant classification in the Transport Model as follows:

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

2.6. The output of the Transport Model is nodal MWkm assigned to either the Peak or Year Round backgrounds. These values are grouped together into generation zones based on areas with similar nodal incremental costs and demand zones (GSP groups).

2.7. The generation zoning criteria is set out in the CUSC Section 14.15.42. These are:

"i.) Zoning is determined using the generation background with the most MWkm of circuits. Zones should contain relevant nodes whose total wider marginal costs from the relevant generation background (as determined from the output from the transport model, the relevant expansion constant and the locational security factor, see below) are all within +/-£1.00/kW (nominal prices) across the zone. This means a maximum spread of £2.00/kW in nominal prices across the zone.

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

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

3. The Sharing Methodology

3.1. This section reviews the sharing methodology which is applied to the year round MWkm as set out in Section 14 of the CUSC which states that

14.15.6 *"A proportion of the marginal km costs for generation are shared incremental km reflecting the ability of differing generation technologies to share transmission investment. This is reflected in charges through the splitting of Year Round marginal km costs for generation into Year Round*

Shared marginal km costs and Year Round Not-Shared marginal km which are then used in the calculation of the wider £/kW generation tariff."

3.2. It should be noted that the approach towards sharing is derived from the work undertaken under CMP213[4] (see Section 4). This sought to recognise in the charging methodology that in certain regions the mix of generation influences constraints and transmission investment drivers (this concept does not appear in the Security Standard). This section considers the process relating to the derivation of shared and not0shared tariffs.

Carbon/Low Carbon

3.3. For the year round background the CUSC subdivides the relevant generation charging base into two categories characterised as "carbon" and "low carbon". The generator classes are set out in the CUSC as follows:

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	

3.4. The classification of generation capacity into "Carbon" or Low Carbon" is an input to sharing methodology.

Boundary Sharing

3.5. The sharing methodology as set out in the CUSC is designed to allocate the "raw" MWkm derived from the transport model on the basis of flows across the zonal boundaries. It assigns the MWkm to either the "shared" or "non-shared" components according to the sharing factors that are assumed in the model as follows (CUSC at 14.15.51):

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

3.6. The "Boundary Sharing Factors" (BSF) are

"*derived from the comparison of the cumulative proportion of Low Carbon and Carbon generation TEC behind each of the incremental MWkm boundary lengths" (CUSC Section 14.15.53).*

[4] CUSC Modification Proposal CMP213, "Project TransmiT TNUoS Developments" at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

3.7. The BSF methodology includes the concept that once the ratio of carbon/low carbon exceeds 50% then the MWkm are deemed to be unshared. This is expressed in the CUSC Section 14.15.53 as follows:

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

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

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

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

Where:
BSF = boundary sharing factor.

3.8. The application of the BSF allows the year round MWkm derived from the Transport Model to be allocated into "shared" or "non-shared" MWkm components. The output from this approach is illustrated with respect to the 2017/18 Year Round Transport Model is illustrated in Table 2.

Table 2: Allocation of year round MWkm to the shared and unshared charging base for 201718 tariffs.

Zone	Zone Name	Unadjusted Transport Zonal Wtd Marginal (km)	Shared Transport Zonal Wtd Marginal (km)	Not Shared Transport Zonal Wtd Marginal (km)
1	North Scotland	1,180.73	488.66	692.06
2	East Aberdeenshire	920.30	228.24	692.06
3	Western Highlands	1,095.39	412.88	682.51
4	Skye and Lochalsh	1,084.87	412.88	671.99
5	Eastern Grampian and	1,025.67	366.46	659.21
6	Central Grampian	1,114.04	413.05	700.99
7	Argyll	1,374.03	328.59	1,045.43
8	The Trossachs	950.01	328.59	621.42
9	Stirlingshire and Fife	698.50	160.17	538.32
10	South West Scotlands	838.86	259.81	579.05
11	Lothian and Borders	629.48	259.81	369.67
12	Solway and Cheviot	457.01	143.11	313.91
13	North East England	255.43	83.59	171.84
14	North Lancashire and T	206.78	83.59	123.18
15	South Lancashire, Yor	29.98	23.26	6.73
16	North Midlands and No	-38.92	-38.92	
17	South Lincolnshire and	-13.72	-13.72	
18	Mid Wales and The Mi	-8.13	-8.13	
19	Anglesey and Snowdo	-69.74	-69.74	
20	Pembrokeshire	-158.98	-158.98	
21	South Wales & Glouce	-161.42	-161.42	
22	Cotswold	-163.34	84.52	-247.86
23	Central London	-140.03	84.52	-224.55
24	Essex and Kent	84.52	84.52	
25	Oxfordshire, Surrey an	-109.22	-109.22	
26	Somerset and Wessex	-160.50	-160.50	
27	West Devon and Cornw	-216.98	-216.98	

Calculation of shared and not-shared tariffs

3.9. The MWkm allow notional year round zonal tariff to be calculated based on the zonal MWkm and application of the expansion factor and the security factor (see Table 3).

Table 3: Notional Year Round tariffs calculated from the Zonal MWkm for 2017/18

Zone	Zone Name	Shared Year Round Zonal Tariff (£/kW)	Not Shared Year Round Zonal Tariff (£/kW)
1	North Scotland	11.94	16.91
2	East Aberdeenshire	5.58	16.91
3	Western Highlands	10.09	16.68
4	Skye and Lochalsh	10.09	16.42
5	Eastern Grampian and Tayside	8.95	16.11
6	Central Grampian	10.09	17.13
7	Argyll	8.03	25.55
8	The Trossachs	8.03	15.18
9	Stirlingshire and Fife	3.91	13.15
10	South West Scotlands	6.35	14.15
11	Lothian and Borders	6.35	9.03
12	Solway and Cheviot	3.50	7.67
13	North East England	2.04	4.20
14	North Lancashire and The Lakes	2.04	3.01
15	South Lancashire, Yorkshire and Humbe	0.57	0.16
16	North Midlands and North Wales	-0.95	
17	South Lincolnshire and North Norfolk	-0.34	
18	Mid Wales and The Midlands	-0.20	
19	Anglesey and Snowdon	-1.70	
20	Pembrokeshire	-3.88	
21	South Wales & Gloucester	-3.94	
22	Cotswold	2.07	-6.06
23	Central London	2.07	-5.49
24	Essex and Kent	2.07	
25	Oxfordshire, Surrey and Sussex	-2.67	
26	Somerset and Wessex	-3.92	
27	West Devon and Cornwall	-5.30	

Application of ALF to Shared Tariffs

3.10. The final stage of the charging process is to apply the year round generation tariffs to users on the basis of their generation capacity (there if no distinction between carbon or low carbon capacity) determined as follows:

- For the shared component the relevant generation capacity is multiplied by the relevant ALF and the relevant tariff and

- For the not shared component the relevant capacity is multiplied by the relevant tariff (**the ALF is not applied).**

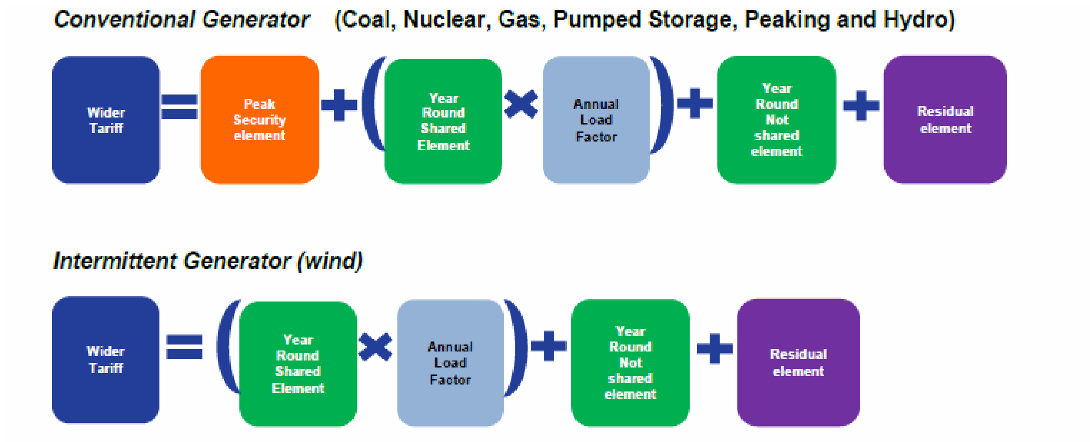
3.11. This is expressed in the CUSC as follows:

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 Not- Shared component whereas the initial tariff for Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery*"

3.12. With regard to the ALF, the CUSC states that

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

3.13. The relevant charging base for transmission tariffs including the year round shared and not-shared tariffs is expressed as follows in the statement of charges for various types of generator[5]:



Final Shared and Not-shared Tariffs

3.14. The final tariffs for 2017/18 are illustrated in Tables 4 and 5 for the year round shared and not-shared components of the tariff.

Table 4: Final applicable shared year round generation tariffs

Derivation of Zonal Generation Tariffs - Shared Year Round						
Zone	Zone Name	Generation Charge Base: TEC Net Stn * ALF	Unadjusted Transport Zonal Wtd Marginal (km)	Shared Transport Zonal Wtd Marginal (km)	Shared Year Round Zonal Tariff (£/kW)	Shared Year Round Zonal Revenue (£m)
1	North Scotland	0.67	1,180.73	488.66	**11.94**	7.98
2	East Aberdeenshire	0.27	920.30	228.24	**5.58**	1.53
3	Western Highlands	0.34	1,095.39	412.88	**10.09**	3.40
4	Skye and Lochalsh	0.03	1,084.87	412.88	**10.09**	0.29
5	Eastern Grampian and Tayside	0.39	1,025.67	366.46	**8.95**	3.45
6	Central Grampian	0.04	1,114.04	413.05	**10.09**	0.44
7	Argyll	0.12	1,374.03	328.59	**8.03**	0.93
8	The Trossachs	0.27	950.01	328.59	**8.03**	2.21
9	Stirlingshire and Fife	0.10	698.50	160.17	**3.91**	0.39
10	South West Scotlands	1.89	838.86	259.81	**6.35**	12.01
11	Lothian and Borders	2.02	629.48	259.81	**6.35**	12.79
12	Solway and Cheviot	0.22	457.01	143.11	**3.50**	0.76
13	North East England	1.38	255.43	83.59	**2.04**	2.82
14	North Lancashire and The Lakes	3.33	206.78	83.59	**2.04**	6.80
15	South Lancashire, Yorkshire and Humber	6.51	29.98	23.26	**0.57**	3.70
16	North Midlands and North Wales	8.51	-38.92	-38.92	**-0.95**	-8.09
17	South Lincolnshire and North Norfolk	2.19	-13.72	-13.72	**-0.34**	-0.73
18	Mid Wales and The Midlands	4.41	-8.13	-8.13	**-0.20**	-0.88
19	Anglesey and Snowdon	0.82	-69.74	-69.74	**-1.70**	-1.40
20	Pembrokeshire	1.51	-158.98	-158.98	**-3.88**	-5.87
21	South Wales & Gloucester	2.48	-161.42	-161.42	**-3.94**	-9.80
22	Cotswold	0.85	-163.34	84.52	**2.07**	1.75
23	Central London	0.00	-140.03	84.52	**2.07**	0.00
24	Essex and Kent	5.00	84.52	84.52	**2.07**	10.32
25	Oxfordshire, Surrey and Sussex	1.63	-109.22	-109.22	**-2.67**	-4.36
26	Somerset and Wessex	1.64	-160.50	-160.50	**-3.92**	-6.44
27	West Devon and Cornwall	0.62	-216.98	-216.98	**-5.30**	-3.30
		47.23				**30.71**

[5] National Grid, "December 2016 Draft TNUoS tariffs for 2017/18", 22 December 2016, page 10

Table 5: Final Applicable non shared year round generation tariffs (including the residual)

Derivation of Zonal Generation Tariffs - Not Shared Year Round & Residual

Zone	Zone Name	Generation Charge Base: TEC Net Stn (MW)	Not Shared Transport Zonal Wtd Marginal (km)	Not Shared Year Round Zonal Tariff (£/kW)	Not Shared Year Round Zonal Revenue (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)
1	North Scotland	1.04	692.06	16.91	17.65	-2.16	-2.25
2	East Aberdeenshire	0.40	692.06	16.91	6.76	-2.16	-0.86
3	Western Highlands	0.48	682.51	16.68	8.09	-2.16	-1.05
4	Skye and Lochalsh	0.04	671.99	16.42	0.68	-2.16	-0.09
5	Eastern Grampian and Tayside	0.55	659.21	16.11	8.90	-2.16	-1.19
6	Central Grampian	0.06	700.99	17.13	1.09	-2.16	-0.14
7	Argyll	0.17	1,045.43	25.55	4.24	-2.16	-0.36
8	The Trossachs	0.52	621.42	15.18	7.90	-2.16	-1.12
9	Stirlingshire and Fife	0.15	538.32	13.15	1.91	-2.16	-0.31
10	South West Scotlands	2.47	579.05	14.15	34.98	-2.16	-5.33
11	Lothian and Borders	2.62	369.67	9.03	23.65	-2.16	-5.65
12	Solway and Cheviot	0.31	313.91	7.67	2.37	-2.16	-0.67
13	North East England	1.72	171.84	4.20	7.24	-2.16	-3.72
14	North Lancashire and The Lakes	4.23	123.18	3.01	12.74	-2.16	-9.14
15	South Lancashire, Yorkshire and Humber	9.47	6.73	0.16	1.56	-2.16	-20.43
16	North Midlands and North Wales	12.47				-2.16	-26.91
17	South Lincolnshire and North Norfolk	3.17				-2.16	-6.83
18	Mid Wales and The Midlands	6.10				-2.16	-13.17
19	Anglesey and Snowdon	1.64				-2.16	-3.55
20	Pembrokeshire	2.20				-2.16	-4.74
21	South Wales & Gloucester	3.61				-2.16	-7.79
22	Cotswold	1.23	-247.86	-6.06	-7.47	-2.16	-2.66
23	Central London	0.00	-224.55	-5.49		-2.16	0.00
24	Essex and Kent	7.00				-2.16	-15.11
25	Oxfordshire, Surrey and Sussex	2.37				-2.16	-5.11
26	Somerset and Wessex	2.14				-2.16	-4.62
27	West Devon and Cornwall	1.05				-2.16	-2.25
		67.23			**132.28**		**-145.05**

4. Discussion on the year round shared and not-shared locational generation tariffs

4.1. There are a number of distinct stages involved in the creation of the year round location tariffs. These are summarised as follows:

- *Allocation of MWkm to Year Round Background*

Stage 1: Scaling generation according the plant types as inputs to the Transport Model based on the SQSS assumptions;

Stage 2: Running the Transport Model to derive MWkm for generation zones for Peak and Year Round backgrounds

- *Allocation of MWkm to Shared/not-shared year round components*

Stage 3: Classification of generation in each zone into “Carbon” or “Low Carbon” categories

Stage 4: Assigning year round MWkm to shared and not-shared components based on BSFs which are based on the proportion of carbon and Low Carbon in each zone

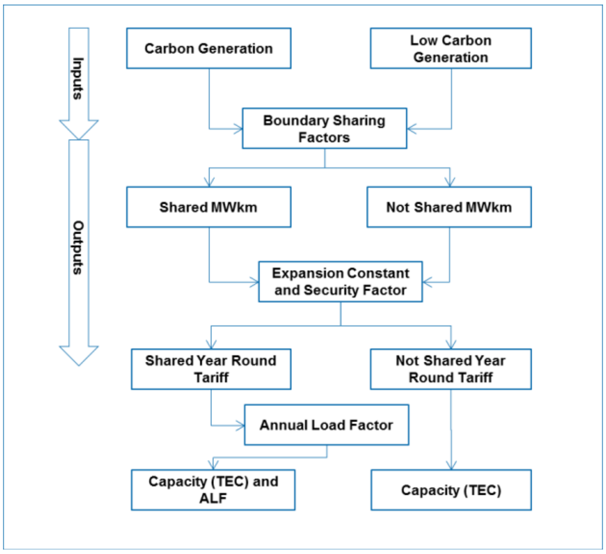
- *Allocation of Tariffs and application to charging base*

Stage 5: Calculating the year round locational tariffs based shared and unshared MWkm, the expansion constant and the security factor

Stage 6: Applying the shared and not-shared tariff to the relevant charging base: shared to generation capacity (Transmission Entry Capacity (TEC)) adjusted for load factor and the not-shared to generation capacity (TEC).

4.2. There stages are described diagrammatically in Figure 1:

Figure 1: The process for setting year round shared and not-shared locational tariffs



4.3. There are number of observations concerning the year round shared and unshared tariff setting process:

- The sharing methodology does not directly relate to the underlying basis of allocating MWkm to the year round background in the Security Standard;
- The concepts associated with the low carbon/carbon split, the BSF, the allocation of year round MWkm to shared and not-shared components and the ALF are constructs of the charging methodology;
- The low carbon/carbon split is a classification used as the basis for sharing and is an input to the boundary sharing methodology; and
- The use of the ALF relates only to the relevant charging base for the shared component of the year round generation tariff (although load factors relate to the constraint analysis).

Discussion on the Carbon/Low Carbon Split

4.4. The CMP213 workgroup described the use of the carbon/low carbon classification as follows:

4.32 "The term 'diversity' was developed by the modelling subgroup to describe the relative volumes of high bid price, low carbon plant using an area of the transmission system compared to the volumes of low bid price carbon plant. It was postulated that diversity could be represented in a zone by categorising plant into "carbon" and "low carbon", and the relative proportion of each would help to quantify the general level of diversity behind a transmission boundary.

4.33 The "low carbon" plant category was defined (for the purposes of CMP213) as containing generation plant that is "must run" and always generates when fuel is available or, for technical reasons is inflexible, irrespective of transmission system need; e.g. demand level. A further characteristic of this type of generation plant is relatively costly (high negative) bid prices. In the case of renewable plant, this results in the need for the generation plant to be paid to *reduce output as fuel is in general low cost or subsidised (ROC or proposed Contracts for Difference (CfD) based) and reduced output results in loss of income for the generator. In the case of existing nuclear plant, flexibility is technically infeasible; however this may not be the case for future nuclear builds where output-based CfD subsidies are expected.*

4.34 The "carbon" category was defined (for the purposes of CMP213) as containing generation plant that is flexible in nature and can reduce/increase output driven by market price and transmission system needs. The principal further characteristic of this generation plant type is that in general it will pay a proportion of its avoided fuel cost, when bid down, to the System Operator, so offering a low cost solution to reducing constraints, providing it is running".

4.5. The workgroup considered the nature of the diversity in zones, the drivers of investment and the causes of constraints. There was discussion about the relative carbon/low carbon split in generation zones and the influence of the split on constraint costs (flexibility versus inflexibility). The workgroup concluded that the carbon/low carbon split was a proxy for the diversity of generation types in a zone.

CMP213 Discussion on Sharing

4.6. The CMP213 working group[6] considered in detail the issues associated with sharing. Essentially discussion centred around the relationship between the generation mix in a zone and the scale and extent of constraints on the transmission system. The ELSI model was utilised to consider the relationship between load factor and constraints.

4.7. The final "Diversity 1" option implemented under CMP213 determined that the carbon/low carbon split should be an input for the derivation of the shared/non shared MWkm. It recognised that as diversity decreased in a generation zone, the costs of constraints would rise as would the required level of investment in the transmission investment.

4.8. The 50% sharing threshold for the BSF was set as a compromise level to recognise the lack of diversity in a generation zone. The absolute level of sharing is determined by the allocation of MWkm to the shared and not-shared components of the tariff using the BSF.

4.9. It was asserted that the greater the dominance of certain inflexible classes of generation the more likely is was that there would be expensive constraints on the system. This resulted in the classification of generation as either low carbon or carbon and the use of this classification as an input to the boundary sharing methodology. The shared tariffs were then applied to generation capacity adjusted for the ALF.

Discussion on the ALF

4.10. The "Diversity 1" approach involves the uses of the ALF in determining the level of sharing for the shared component of the tariff. The workgroup suggested that that the "Diversity 1" option:

"4.68… was potentially more cost reflective than the Original [which did not include sharing]. This is because the sharing element is applied based on an individual generator's ALF, whilst also reflecting the cost of low diversity behind a boundary linked to large negative bid prices. These members therefore believed that this

[6] Final CUSC Modification Report, CMP213 Project TransmiT TNUoS Developments at http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

potential alternative better recognises a generator's individual impact on expected transmission investment".

4.11. It was noted in the discussion on Diversity 1that:

"4.70 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".

4.12. The charging methodology assumes that below the 50% threshold generators in a zone can share the transmission system based on ALF, but above the 50% level the generation capacity cannot share the transmission system. The use of the ALF in the charging base was thought to reflect to some extent the fact that the level of constraints was considered to be a function of load factor up to the threshold level.

CMP213 Ofgem Decision and Sharing

4.13. In the context of the sharing methodology Ofgem noted the following:

2.16. "In addition, by splitting the Year Round tariff into 'shared' and 'non-shared' elements, WACM 2 also recognises that the mix of plant in an area will have an impact on the level of constraint costs. This is because, in zones dominated by low carbon plant, these generators are less able to efficiently 'share' transmission network capacity because they tend to run simultaneously (e.g. when the wind is blowing). They are also expensive to constrain off compared to other forms of generation. Constraint costs will therefore tend to be higher in zones with high concentrations of low carbon plant. The non-shared element of Year Round tariff therefore increases as low carbon plant exceeds 50% in a zone and is not adjusted for ALF in recognition of this effect"[7].

5. The CMP268 Proposal and sharing

5.1. The CMP268 proposal seeks to recognise 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"[8].

5.2. The proposal goes on to states that:

"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%".

5.3. In terms of a potential solution, the modification proposal proposes:

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[7] CMP213 Ofgem Decision Letter

[8] CMP268 Modification Proposal

"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 pay. 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".

5.4. CMP268 suggests that the carbon and low carbon split is a function of bid type while the conventional intermittent classification used for peak charges as related to dispatch. This enables at 4 types of generation to be identified, which are characterised as conventional or intermittent as well as carbon and low carbon. This classification is illustrated in Figure 2.

Figure 2: CMP268 classification of generation type for the sharing 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

5.5. CMP268 raises a number of issues with regard to the sharing methodology. In particular:

- The nature of the carbon/low carbon split as inputs to the BSFs;
- The scale and extent to which different types of generator contribute to constraints;
- The basis of the allocation into shared and not-shared MWkm components; and
- The nature of the charging base for the resultant shared/non shared tariffs

5.6. The implications of each of these issues for the sharing methodology are considered in turn in the following sections.

Carbon/Low Carbon classification

5.7. CMP268 asserts that the current low carbon/carbon classification does not reflect the impact of different types of generator on transmission investment and constraint costs. The proposal refers to analysis of the ALF in the CMP213 Working Group report. In particular it cites analysis associated with the incremental constraint cost and load factor.

5.8. However, as noted in this paper the carbon/low carbon split together with the assumed sharing/non sharing threshold is an input to the sharing methodology. Therefore if we wish to alter the classification of plant, then we have to reallocate certain plant from low carbon to carbon in order to impact on the MWkm allocated to either the shared background or the not-shared background. CMP268 makes no such proposal.

5.9. There may be merit is considering whether the characterisation of plant is appropriate as an input to the sharing methodology under CMP268, particularly if that better reflects the underlying drivers of constraints. For example, plant could be characterised as flexible/inflexible or dispatchable/non dispatchable. However this would simply impact on the capacity of generation allocated to each category and therefore the MWkm allocated to the shared or not-shared components of the tariff.

Generation types and constraints

5.10. CMP213 asserts the "*for a conventional carbon plant, the impact on constraint cost remains a function of their ALF irrespective of the proportion of low carbon plant it is sharing with*"[9].

5.11. CMP268 cites evidence from the CMP213 report about the relationship between load factor and constraint costs. This analysis is associated with the Diversity 1 model and is used to illustrate the fact that constraint costs increase based on the generation mix within generation zones. Clearly the type of plant within a zone influences this relationship, and the low carbon/carbon characterisation was an attempt to recognise that beyond a certain point constraint costs continue rise significantly if there is insufficient diversity of plant (i.e. carbon or low carbon; flexible or dispatchable) in a zone.

5.12. CMP268 therefore raises issues about the relationship between the generation mix in a zone and sharing factors. In order to address these issues, further work would be required to consider whether the assumptions under CMP213 about load factor and zonal generation mix remain valid and whether constraints rise significantly in a zone dominated by low carbon or carbon plant above a certain percentage level. However, this analysis would relate to the classification of plant (carbon/low carbon) and the threshold level for the sharing/non sharing allocation of MWkm under the current sharing methodology.

The allocation process and the BSFs

5.13. As noted above the low carbon/carbon split and the sharing factor allow the MWkm in the charging model to be allocated to either the shared or not-shared component of the tariff. CMP268 may impact on this process if it is determined that certain categories of plant are allocated to the shared element of the MWkm rather than the shared component.

5.14. As part of the work associated with CMP268 it may be appropriate to consider the current boundary sharing threshold, which is currently set at 50%. Analysis of zonal diversity, load factor and constraints may enable this level to be set differently. This would enable the MWkm allocated to the shared and not-shared components to be adjusted.

5.15. The CMP213 workgroup considered the issues associated with the BSF. Based on the work group analysis, work group reports states[10]:

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[9] CMP213 Modification Proposal

[10] CMP213 Workgroup Report, Paragraph 4.41

"there is potentially a generator load factor relationship that allows the sharing of the transmission network between carbon and low carbon plant. This relationship is linear with load factor until 50% of generation behind a transmission boundary is dominated by ***either low carbon plant or carbon plant****, after this a load factor multiple (a diversity factor) needs to be applied to both classes of generation plant to represent the incremental constraint cost. This then serves to reduce the impact of load factor as a direct proxy for sharing." [emphasis added]*

5.16. This quote from the workgroup report is important in the context of CMP213 since it highlights that it is the lack of diversity in a zone that drives constraints. This seems to be at odds with the suggestion in CMP268 that "conventional plant" should be relieved from the non-shared component of the tariff by the application of the ALF.

The shared not-shared charging base

5.17. CMP268 proposes that for the not-shared component of the locational tariff:

- "conventional" generation is relieved of its obligation to pay the shared year round component of the tariff by applying the ALF to the shared element of the tariff; and
- "non-conventional generation" continue to pay the not-shared component of the tariff based on capacity (TEC).

5.18. The CMP268 approach seems to misunderstand the nature of the ALF in its application under the charging methodology. The ALF is used to determine the basis of sharing for the shared component of the tariff. The not-shared component is by definition not shared. Therefore to relieve certain categories of generator from this not-shared tariff would appear to be unjustified.

Implications

5.19. CMP268 raises issues associated with the sharing methodology in the CUSC. These may be characterised as follows:

- The characterisation of generating plant as carbon/low carbon may be inappropriate. CMP268 raises the prospect of distinguishing between "conventional" and "non-conventional plant" or some other characterisation of plant for the purpose of sharing (perhaps flexible/inflexible);
- The basis of the 50% sharing factor is to some extent arbitrary. However, it is unclear as to whether the level should be lower (reflecting low "diversity") or higher reflecting the impact of "conventional" generation", or perhaps on some other basis altogether;
- The approach towards sharing/non sharing in the charging base may require review. Perhaps there is some other basis of sharing that should be applied to the shared or not-shared locational component of the year round tariff; and
- CMP268 requires confirmation that the not-shared MWkm and locational year round tariff can be shared on the basis of ALF. However there is no evidence that this is the case. For the purpose of charging it is assumed that not shared MWkm cannot be shared. Consequently, it is difficult to understand how not shared MWkm can be shared.

5.20. CMP268 also highlights that the sharing methodology is not directly related to the Security Standard. Rather it is the construct of the CMP213 charging methodology. The CMP213 workgroup suggested that it was more cost reflective to include sharing but that was in the context of the entire CMP213 modification proposal. The key consideration for CMP268 is the cost reflectivity of the sharing methodology itself.

5.21. The Security Standard does not distinguish between elements that are derived by the diversity of carbon or low carbon technologies in zones and does not include any direct reference to differential investment drivers dependent on diversity. As noted above the allocation of the MWkm to the year round background is simply based on the Security Standard scaling factors. Therefore, CMP268 may call in question the cost reflectivity this specific element of the charging methodology in allocating MWkm in the context of the Security Standard.

6. Conclusions

6.1. This paper has considered the issues associated with CMP268 and the potential application of the ALF to the not-shared component of the locational year round generation tariff. In particular it highlights the relationship between constraints and transmission investment and the application of the methodology to individual plant within zones. The following factors should be noted:

- The sharing methodology allocates plant in a zone according to the low carbon/carbon categories based on historic analysis and determines the level of “diversity” in a generation zone;
- The BSF is the critical element that determines the extent of sharing (50%) between carbon and low carbon;
- The methodology allocates MWkm into shared or not-shared components of the tariffs;
- The shared component to the tariff is shared according to generation capacity adjusted by ALF;
- The not-shared component is allocated to generation capacity (TEC)

6.2. CMP268 seeks to relieve conventional generation from the not-shared component of the tariff by applying the ALF to the shared component of the locational year round tariff. This seems to misunderstand the nature of the ALF in the sharing methodology which simply represents the means by which the shared component of the tariff is shared. By definition, the not-shared component of the year round tariff cannot be “shared” according to ALF.

Bill Reed
RWE Supply and Trading GmbH

January 2017

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Annex A: Security standard scaling for the “peak” background

Appendix C Modelling of Security Planned Transfer

Availability Factors

C.2 In derivation of Security planned transfer conditions, the registered capacities of power stations are scaled by availability factors, known as AT, for classes T of power station. For the Security planned transfer condition, these factors are set as follows:

C.2.1 For stations powered by wind, wave, or tides, AT = 0. This zero factor is set for the Security planned transfer condition so that there is confidence that there is sufficient transmission capacity to meet demand securely in the absence of this class of generation.

C.2.2 For imports or exports from / to external systems, AT = 0.

C.2.3 For all other power stations, AT = 1.0

Annex 5 – Authority send back letter

Making a positive difference
for energy consumers

Mike Toms
Independent CUSC Panel Chair
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National Grid House
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Direct Dial: 0207 901 1857
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Date: 02 December 2016

Dear Mike

Authority decision to direct that the modification report on CUSC modification proposal CMP268 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits' be revised and resubmitted

On 26 July 2016, for SSE (the 'Proposer') raised Connection and Use of System Code (CUSC) modification proposal CUSC Modification Proposal (CMP) 268, 'Recognition of sharing by Conventional Carbon plant of Not-Shared Year-Round circuits', requesting that it be treated as an Urgent CUSC Modification Proposal. On 2 August 2016, the CUSC Modifications Panel (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 was commercially sensitive and confidential, and was therefore not submitted to the Panel. We considered both the Panel's and the Proposer's arguments, and on 23 August 2016 published a letter confirming CMP268 could be progressed on an urgent basis. Our letter made clear that we expected a sufficient level of analysis and stakeholder engagement to have been undertaken demonstrating that the proposal better facilitates the CUSC Relevant Objectives.

On 23 November 2016, the CUSC Panel submitted a Final Modification Report (FMR) for CMP268 to the Authority. We have decided that we cannot form an opinion on CMP268 based on the information submitted and we therefore direct that the FMR is revised and resubmitted. We recognise the work carried out through the industry process to date to assess the evidence for the defect that CMP268 describes and the proposed solution. However, we consider that there are areas that can be further addressed through additional industry assessment that are necessary to inform our decision on the modification.

Issues to address

The modification suggests that the current system of charging for conventional generation is not cost-reflective and places an unreasonable level of charges on Conventional carbon generators. The modification proposal suggests that different types of conventional generation lead to different needs for investment in areas of high renewable penetration and so different costs, and aims to better recognise this in the methodology. The modification proposes that for conventional carbon generators the Not-Shared Year-Round element of the tariff is scaled by the generator's annual load factor.

We have identified the following reasons why we cannot make a decision without further consideration by the workgroup, the Panel and industry –

1. The proposer has set out a theoretical basis for their suggested defect, and provided some evidence to support this. Other workgroup members and respondents to the consultation have provided some evidence and arguments to the contrary. However, in our view there has ultimately not proved to have been sufficient time within the urgency process in this case for industry, the workgroup and the panel to thoroughly consider and submit the robust evidence required in order for us to make a fully informed decision on the merits of the proposal.

2. Given the constraints of the urgency process it has not ultimately been possible in this case for the FMR to provide sufficient analysis or discussion of the potential future impacts of making this change.

We therefore direct that additional steps are undertaken (including sending the proposal back to the CMP268 working group for further consideration and/or undertaking further consultation if it considers this appropriate) to address these concerns.–

1. We consider that the workgroup should be reconvened to further consider the evidence submitted so far and to consider whether any further evidence is required to allow the Panel and us to properly consider the merits of the proposal.

2. The FMR should consider in more depth the potential impacts of the proposed solution, as compared to retaining the current system.

3. The workgroup should consider whether further consultation on the proposals and evidence is approriate (following completion of steps 1. and 2.)

We note that the analysis for CMP268 was largely from the CMP213 documents and work associated with the process, and as such is several years old. We accept that this was necessary given the limited timescales, though we think that more up-to-date analysis is required.

It would also be helpful to ensure that all evidence has been made available to workgroup and industry parties at the same time and that the workgroup discussions resulting from all evidence can be reflected in the FMR. For instance, significant new evidence should be provided before consultations, rather than as part of a consultation response, to allow for more productive workgroup discussions.

Further, we recognise that under the urgent process there was not time to consider if any alternative proposals to address the defect could be developed by the industry. We consider this is a matter that the work group could consider further. We expect the industry timetable for developing any alternative proposals (if appropriate) should ensure that we are in a position to make a decision on such proposals together.

After addressing the issues discussed above, and revising the FMR accordingly, the CUSC Panel should re-submit it to us for decision as soon as practicable.

Yours sincerely

Andrew Self
Head of Electricity Network Charging, Energy Systems
Signed on behalf of the Authority and authorised for that purpose

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Annex 6 – Workgroup Attendance Register

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

Name	Organisation	Role	16/01	20/02	13/03	06/04	04/05
Chrissie Brown	Code Administrator	Technical secretary	**A**	**A**	**A**	**A**	**A**
Ryan Place	Code Administrator	Chair	**A**	**A**	**A**	**A**	**A**
John Tindal	SSE (Proposer)	Workgroup member	**A**	**A**	**A**	**A**	**D**
Bill Reed	RWE	Workgroup member	**A**	**A**	**A**	**A**	**A**
Paul Jones	Uniper	Workgroup member	**A**	**X**	**A**	**A**	**A**
James Anderson	Scottish Power	Workgroup member	**A**	**A**	**A**	**A**	**A**
Paul Mott	EDF Energy	Workgroup member	**A**	**A**	**A**	**A**	**D**
Damian Clough	National Grid	Workgroup member	**A**	**X**	**A**	**A**	**A**
Andrew Malley	Ofgem	Authority representative	**A**	**A**	**A**	**A**	**D**

nationalgrid

Stage 06: Final Modification Report

Connection and Use of System Code (CUSC)

CMP268

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

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.

What stage is this document at?

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

Published on: **23 November 2016**

High Impact: Generation TNUoS payers.

The CUSC Panel Recommendation:

At the CUSC Modifications Panel meeting on 15 November 2016, the panel voted on CMP268 Original against the applicable CUSC Objectives. The Panel voted by majority that the Baseline better facilitates the CUSC Objectives.

Contents

Any Questions?

Contact:
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Code Administrator

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Proposer:
John Tindal
SSE

About this document

This is the Final CUSC Modification Report which contains responses to the Code Administrator Consultation and details of the CUSC Panel Recommendation vote. This report has been prepared and issued by National Grid as Code Administrator under the rules and procedures specified in the CUSC. The purpose of this document is to assist the CUSC Panel in making their recommendation on whether to implement CMP268.

Document Control

Version	Date	Author	Change Reference
1.0	23/11/2016	Code Administrator	Final Modification Report

1 Summary

1.1 This document seeks to describe the Original CMP268 CUSC Modification Proposal and includes the responses to the Workgroup and Code Administration consultations.

1.2 CMP268 was proposed by SSE and was submitted to the CUSC Modification 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 outlining the case for urgency is set out in Appendix 6. The timetable for urgent consideration is set out in the Terms of Reference in Appendix 2.

1.3 CMP268 aims to change the charging methodology to suitably recognise that different types of "Conventional" generation cause different transmission network investment costs, which should be reflected in the TNUoS charges paid by different types of "Conventional" generation. The change to the charging methodology would apply to those generators which are classed as Conventional Carbon and, their generator's ALF would be applied to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements. This would not change the way the Year-Round tariff is calculated or the existing generator classifications, but it would 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 whereby 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.

1.5 This Final Modification Workgroup Report 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

1.6 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 it takes better account of the developments in Transmission businesses. The remaining 5 Workgroup members voted that the Baseline is better against the applicable CUSC Objectives because there is no clarity that by applying ALF to the non-shared element; it is more cost reflective and that the current cost signals are correct when applying diversity in a zone.

Consultations

1.7 The Workgroup consulted with the Industry and received six responses by the closing date of 30th September 2016. A summary of these responses can be found in Section 7 and full responses are included within Annex 7 of this document

1.8 The Code Administrator Consultation also received six responses and closed for consultation on3rd November 2016. A summary of these responses can be found in Section 8 of this document and full responses are included within Annex 8.

CUSC Panel Recommendation

1.9 At the CUSC Modification Panel meeting on 15th November 2016, the Panel voted on the CMP268 Original against the Applicable CUSC Objectives. Kyle Martin was absent from the meeting and passed on his voting rights to Garth Graham as well as Cem Suleyman who was absent from the meeting and passed on his voting rights to James Anderson. The Panel agreed by majority that the Baseline better facilitates the Applicable CUSC Objectives.

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/

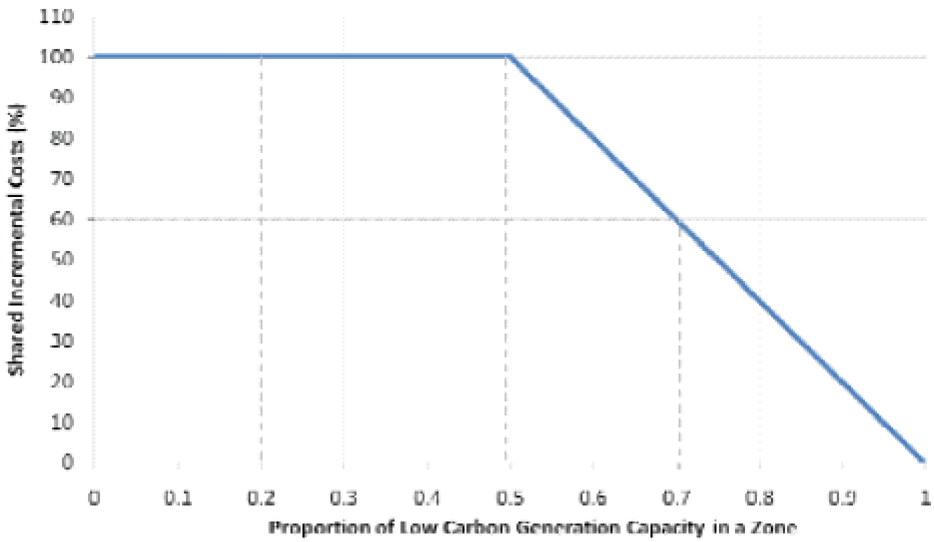


Figure 1: Taken from "Figure 18" from the CMP213 Workgroup Final report.

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.

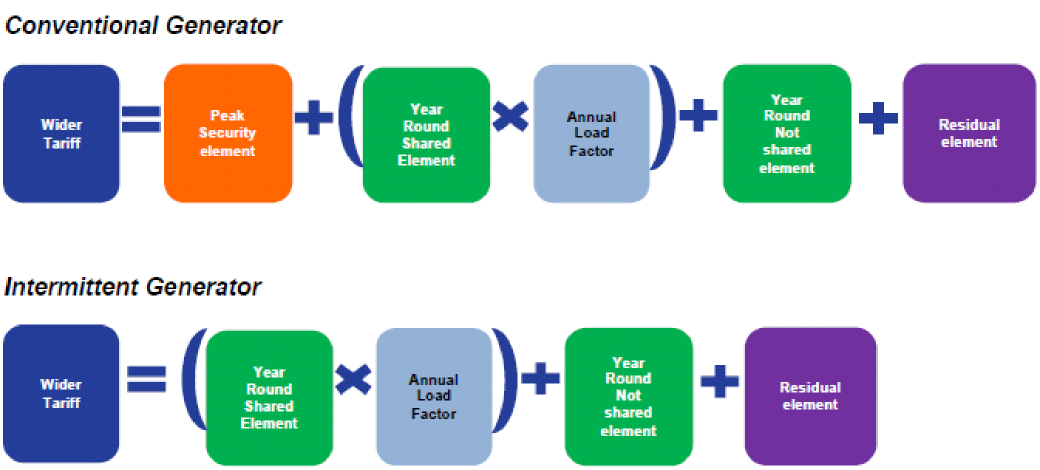


Figure 2: Charging Methodology

Purpose of the proposal

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.

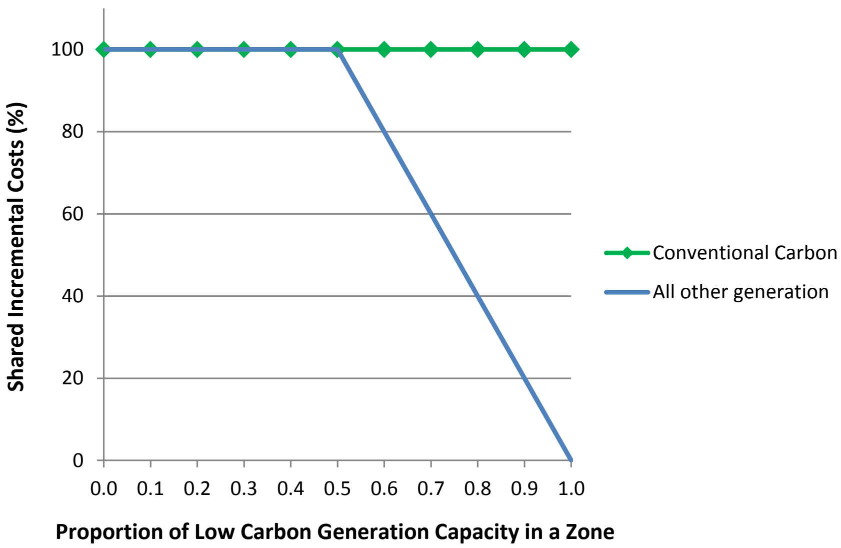
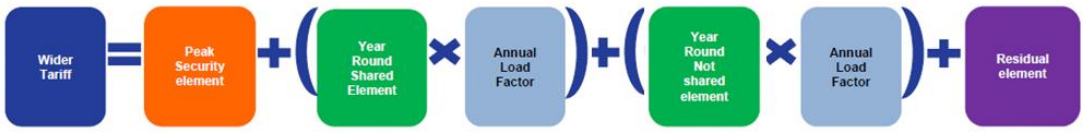


Figure 3: Proposed change - Modified Figure 1

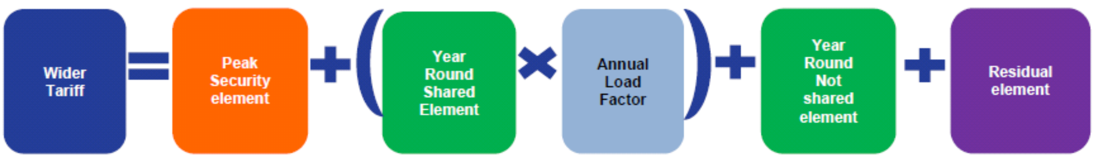
2.30 The Proposer highlights that this modification proposal will recognise that even when the proportion of “Low Carbon” plant influencing a boundary is close to 100%, then it is more cost reflective that conventional carbon plant should have its ALF applied to the whole Year-Round tariff (both Shared 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:

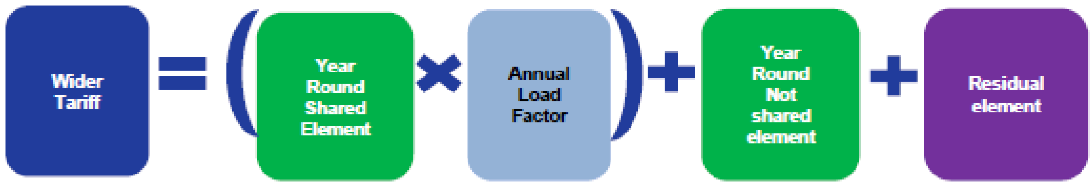
2.31.1 ***Adjusted tariff formula: “Conventional Generator – Carbon”*** - This represents a change from the existing “Conventional Generator” tariff formula since it applies the Generator’s ALF to both its Not-Shared Year-Round as well as its Shared Year-Round tariff elements.



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:

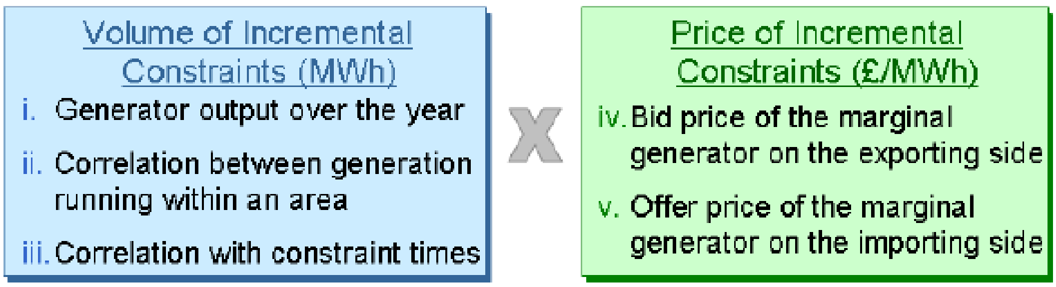


Figure 5 – Components that drive transmission constraint costs

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.

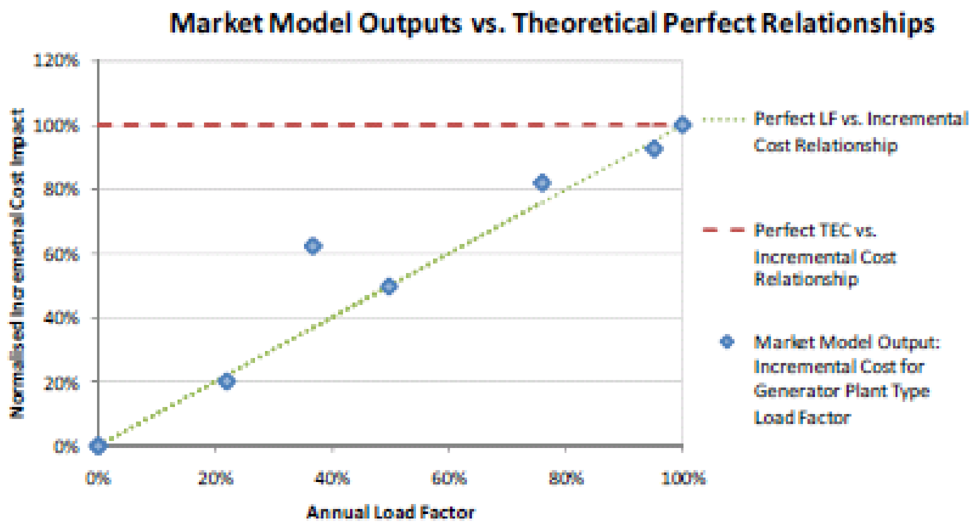


Figure 1 – Market Model Outputs vs. Theoretical Perfect Relationships

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.

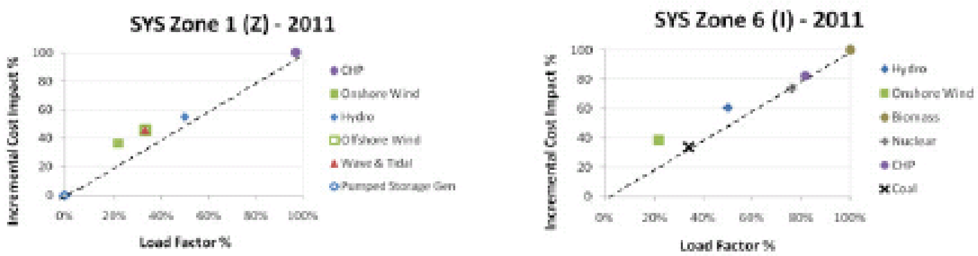


Figure 2 – Example ELSI analysis

<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%.

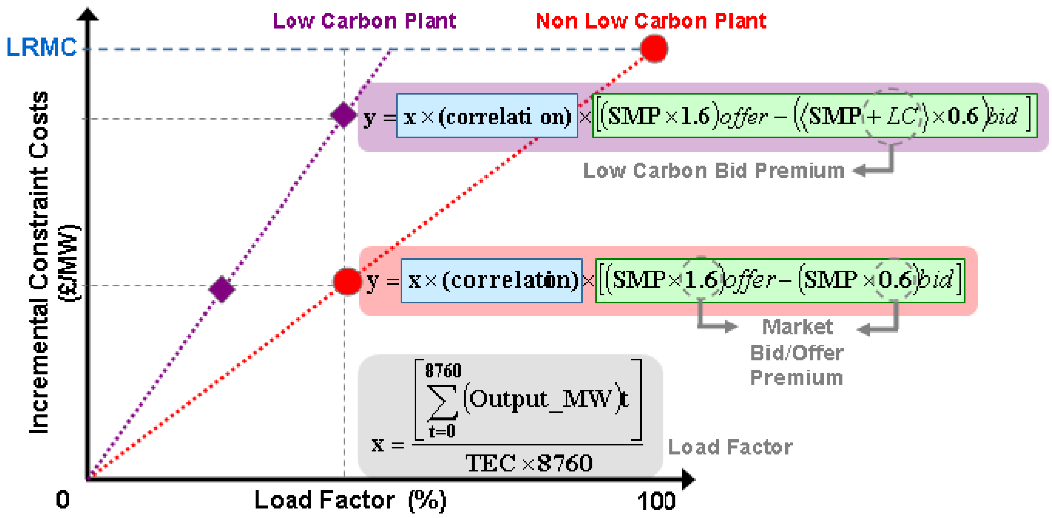


Figure 21 – Combined effect of price and load factor on constraint costs

<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.

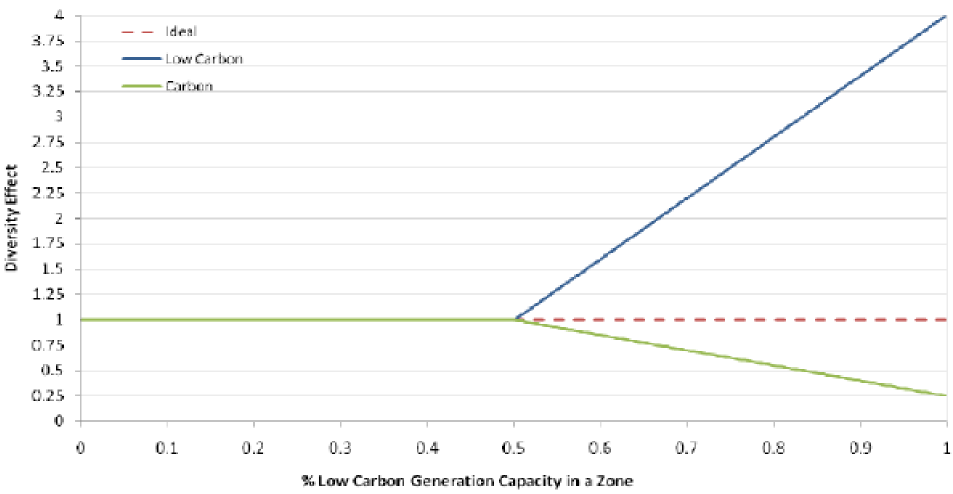


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

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.

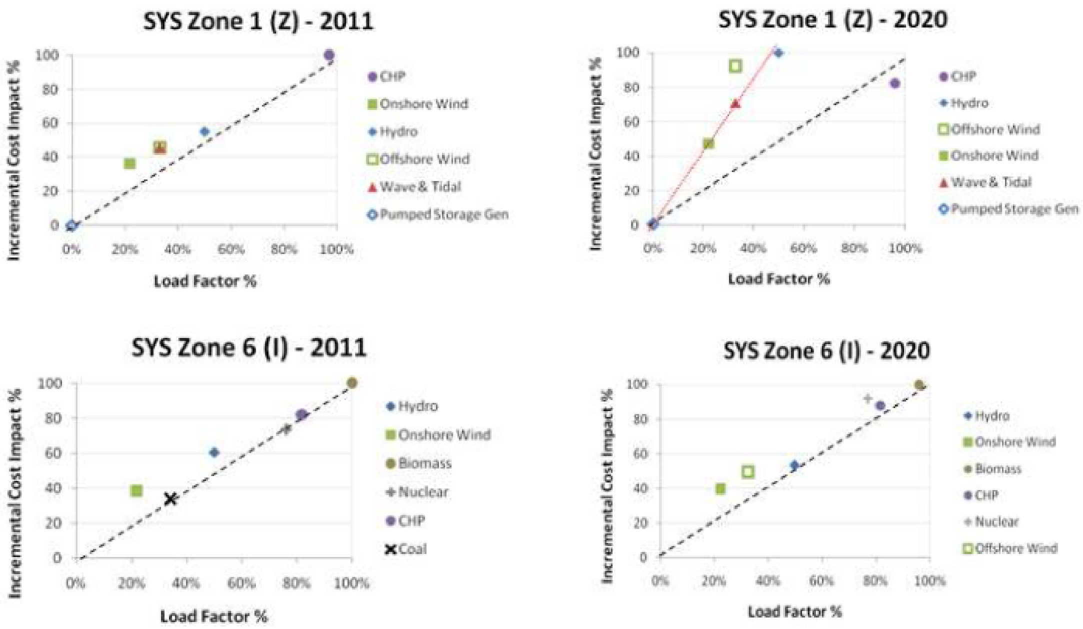
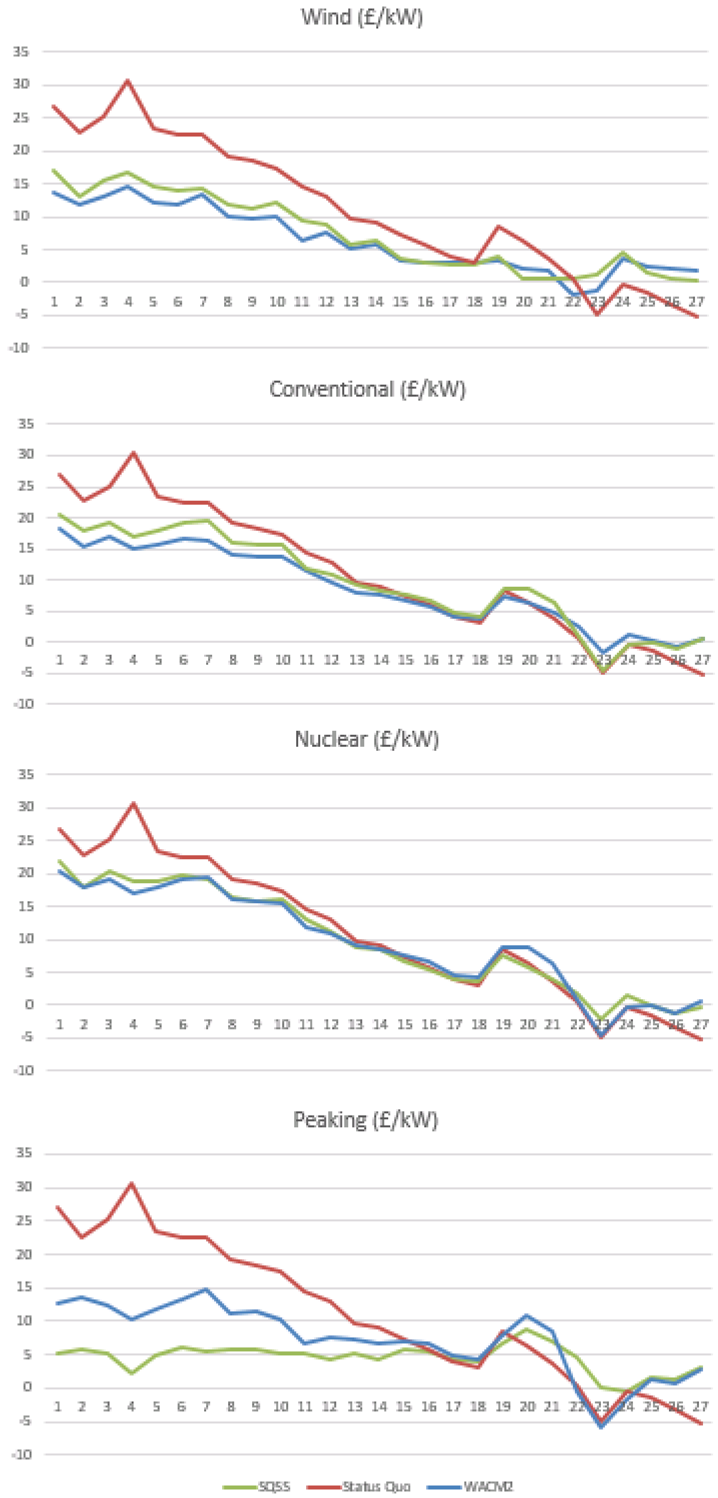


Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

<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.

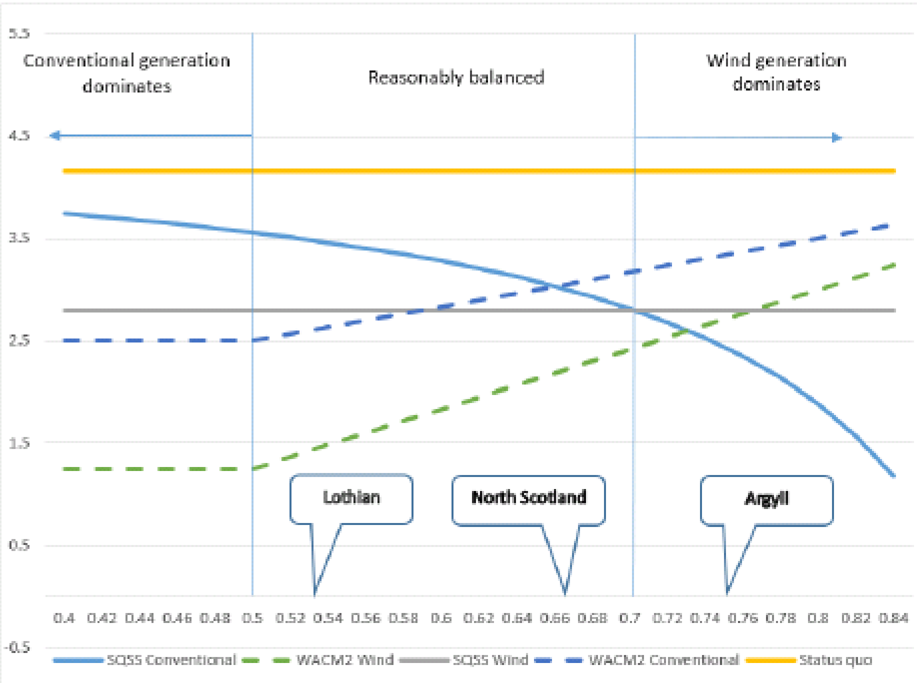


Figure 4. Variation of SQSS costs (£/kW) and WACM2 & Status Quo charges (£/kW) with sharing

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

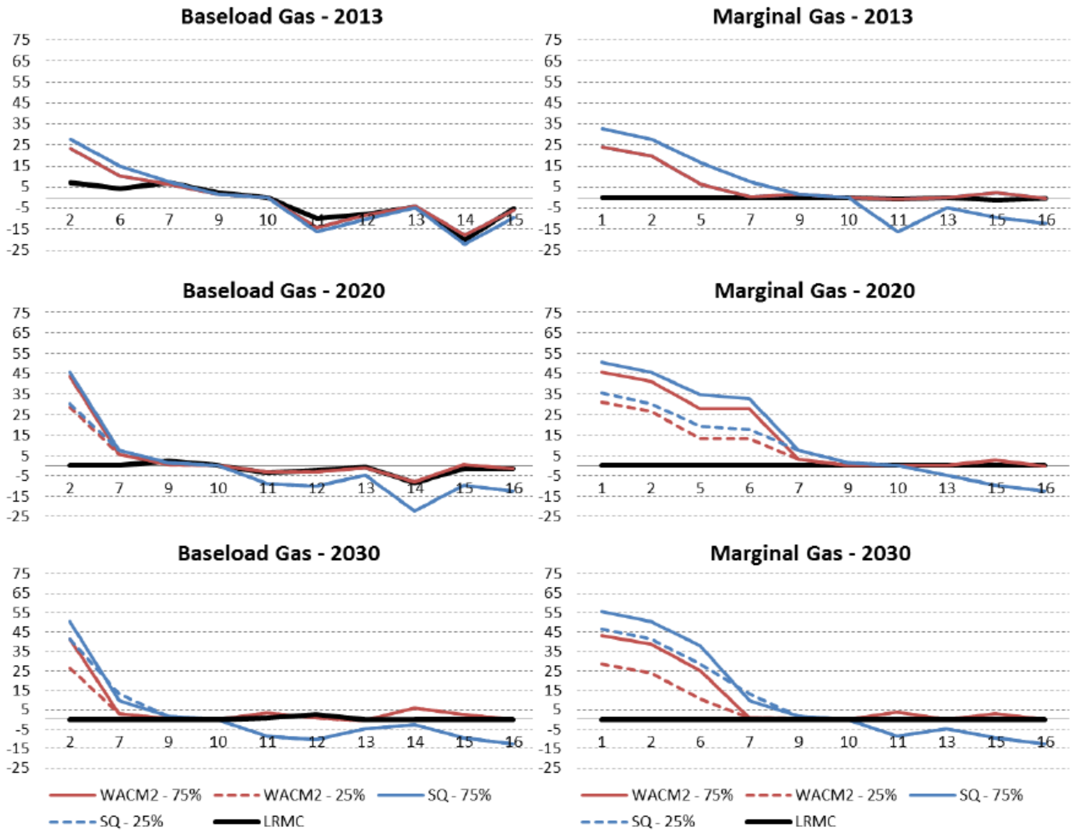
3.19 The proposer presented evidence showing a comparison with Long-run marginal cost modelling produced by NEAR/Imperial suggesting that CMP213 WACM2 may be over charging Conventional Carbon generators located in zones dominated by low carbon generation.

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) CMP213 Analysis

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.

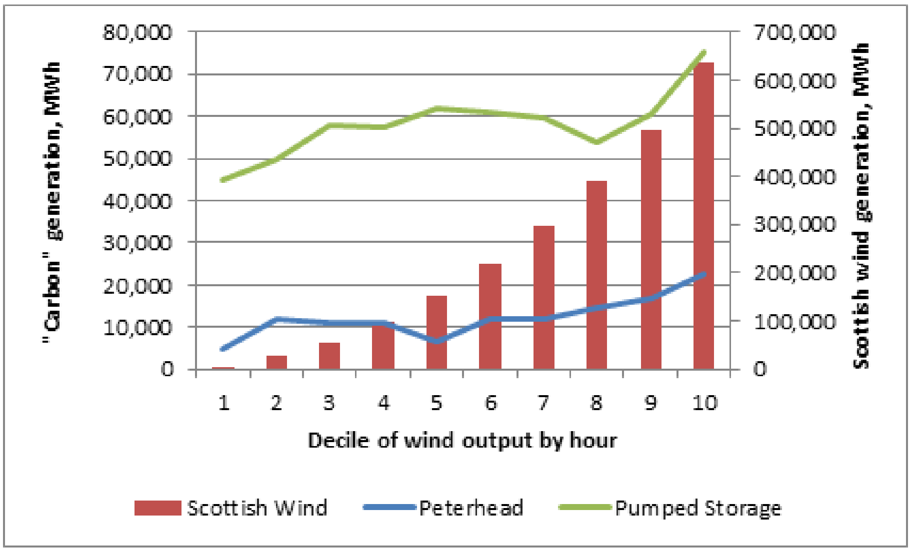


Figure 4: 2015 Analysis

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.

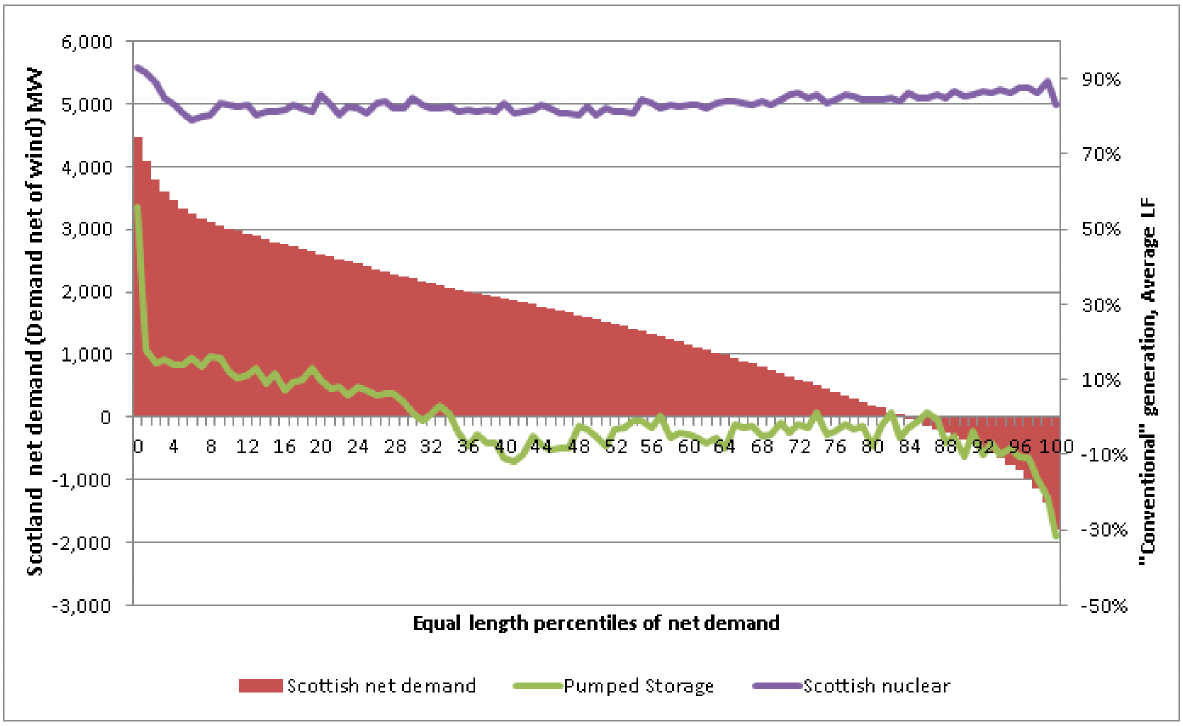


Figure 5: Net Demand Profile for Scotland

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) <u>Distributional Impact</u>

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 <u>locational</u> impact of this modification. <u>All</u> 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

[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.

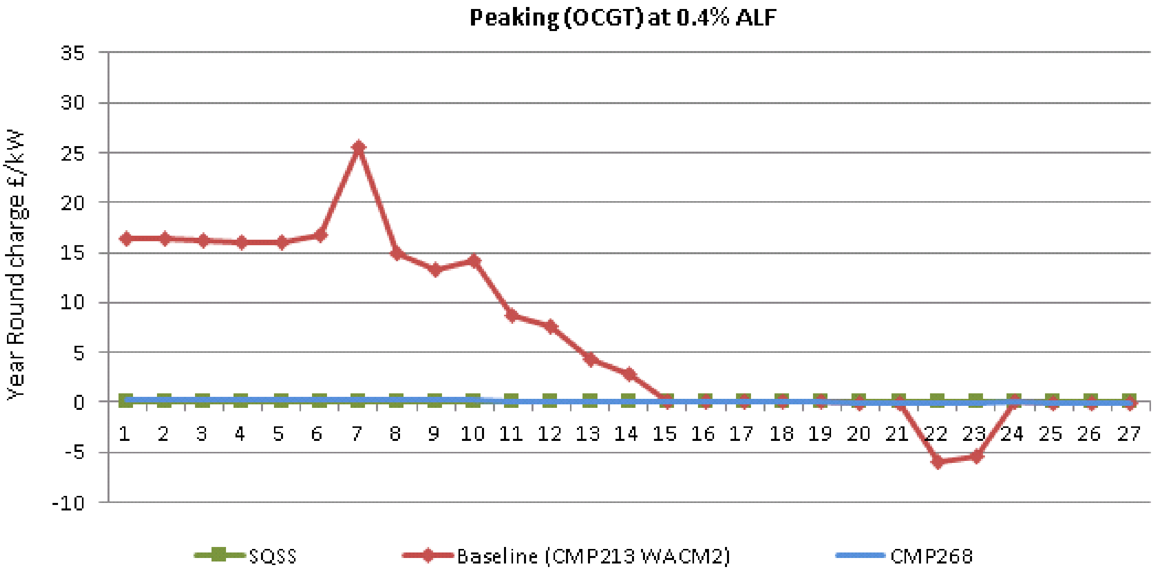
4.57 The proposer moved onto explain the next part of the analysis below:

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.



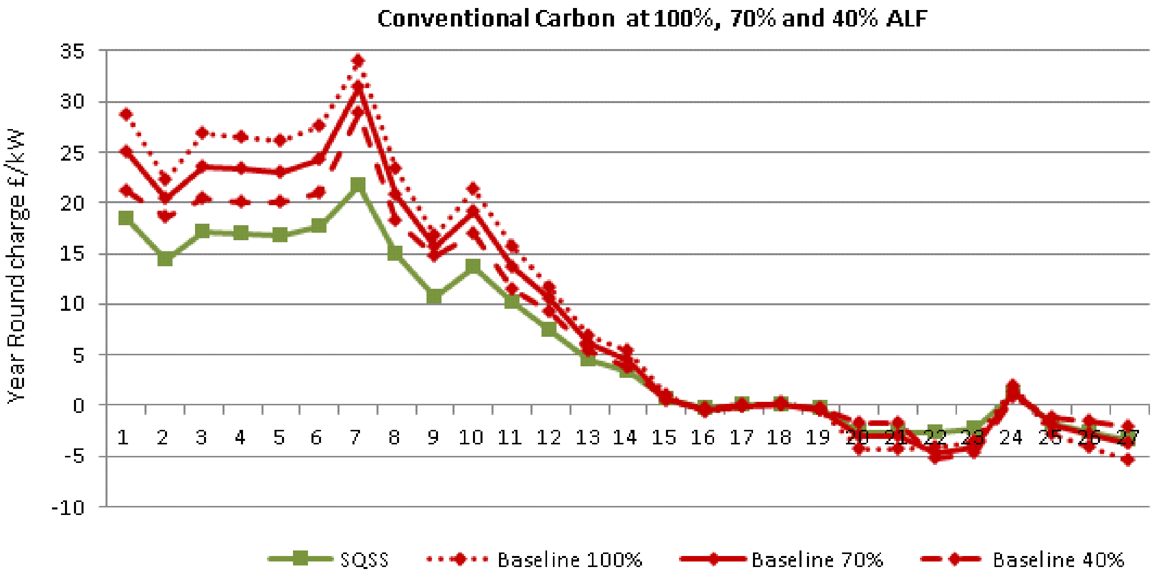
4.59 A Workgroup member stated that the SQSS factor does not drive the charge that the generator would pay, it was the ALF, and as such the analysis was not comparing similar things. He went onto question the relevance of the graph provided and said that all it really showed was that a Year Round charge 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.

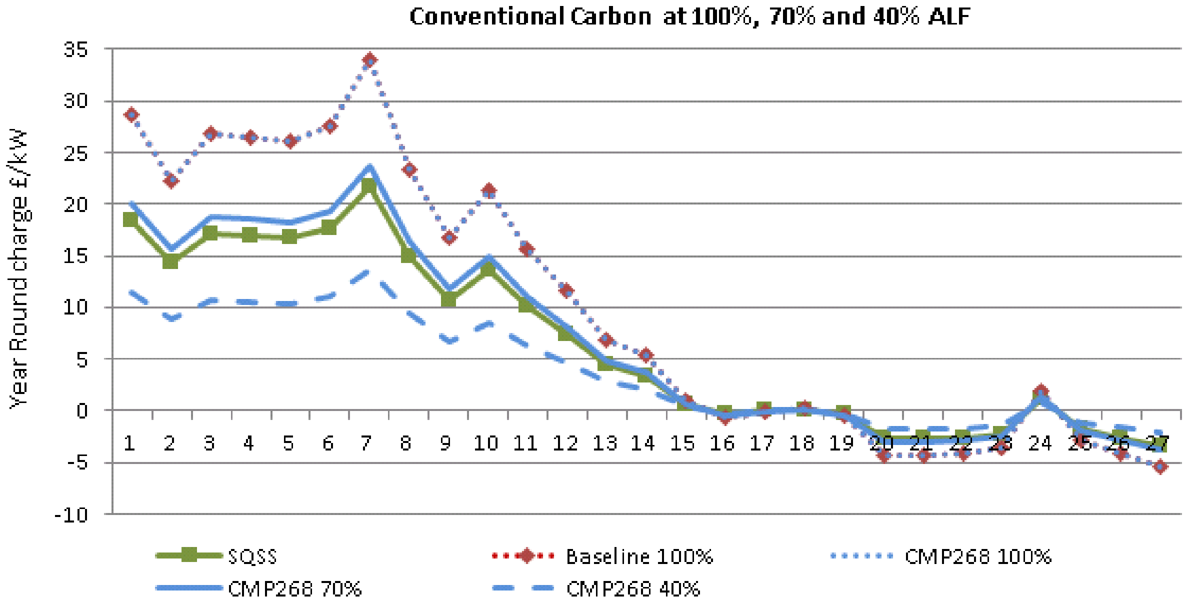
4.61 The Workgroup debated the use of ALFs within charging. It was suggested by some Workgroup members that the proposer's analysis implies that the defect lies in the fact that the ALFs differ from the SQSS factors. An example of this is when wind has an SQSS scaling factor of seventy percent, but wind 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.

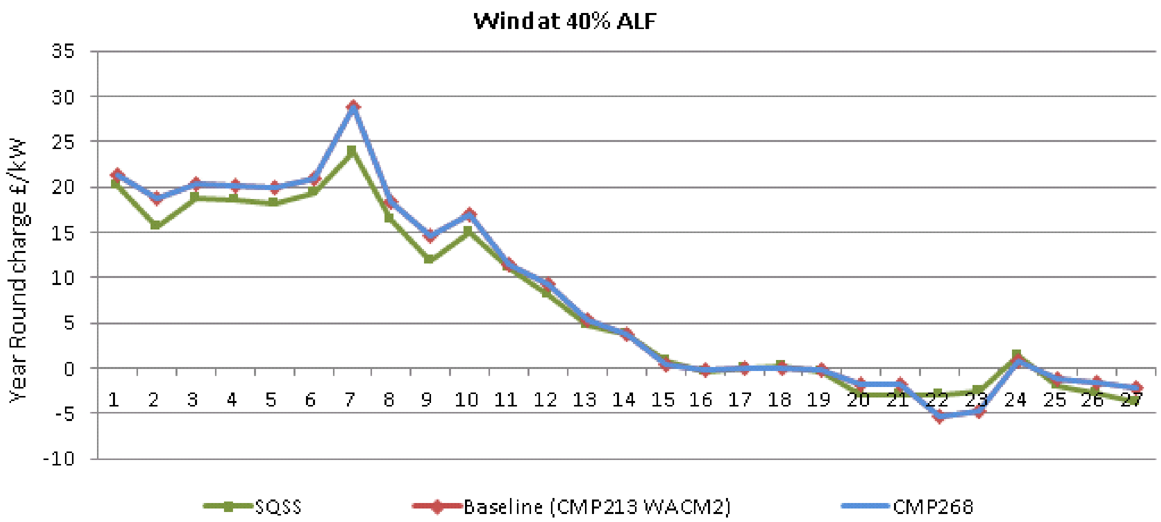
4.69 This Workgroup member noted that a lack of diversity was stated as the reasons why the relationship between ALF and constraint costs broke down and why the network would then be built to meet close to the total capacity of plant behind a boundary, both carbon and low carbon. The Workgroup member 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.

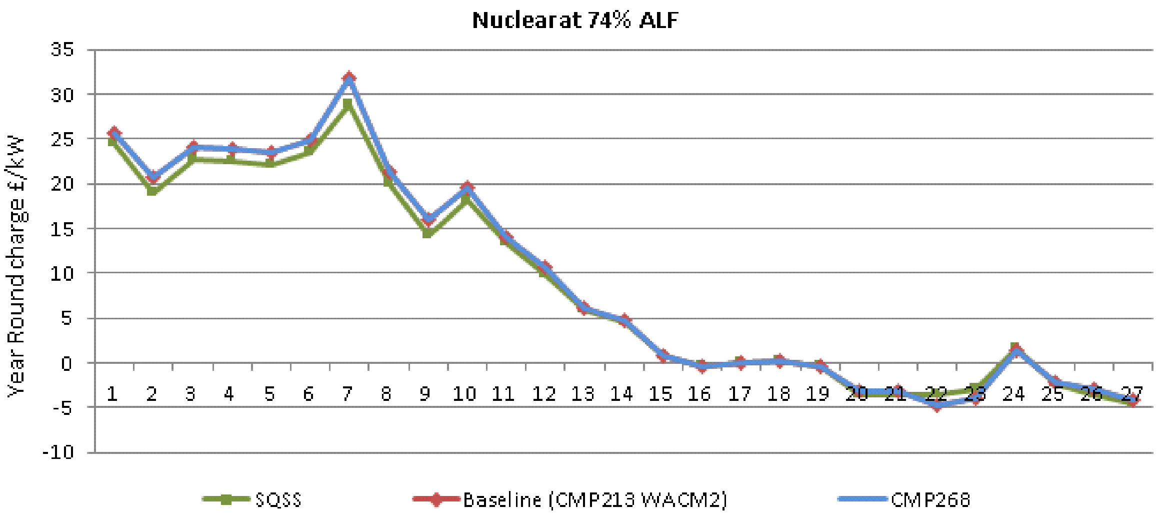
4.70 The proposer stated that conventional carbon does not cause a constraint cost as it's a low cost to come off of the system and as a result are not breaking down sharing. It was suggested by another Workgroup member that this would be a lower cost than low carbon plant, not necessarily low or zero. 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

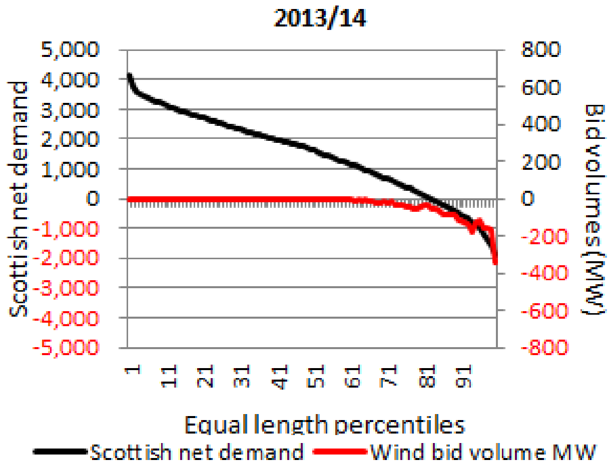
4.74 The proposer stated that SSE carried out analysis comparing MWh volumes for FPNs, Bids and Offers for Conventional Carbon generators (CCGT and Pumped Hydro) in Scotland compared with net demand in the three financial years of 2013/14, 2014/15 and 2015/16. He stated that this analysis suggested that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

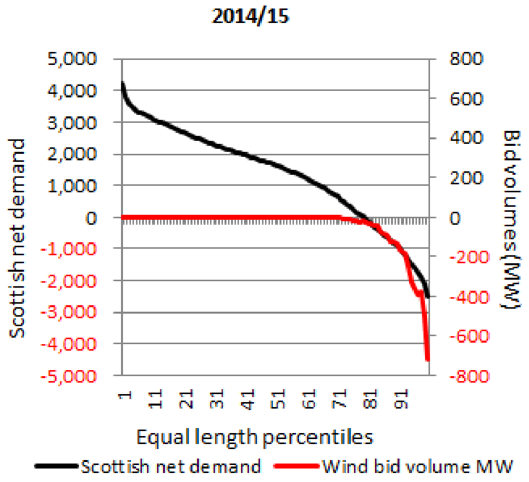
4.75 He noted that Scottish net demand was calculated as Scottish demand minus Scottish wind generation. This used National Grid published INDO demand, adding back in embedded wind, then applying a 9% pro-rata adjustment[13] to derive an equivalent figure for Scottish demand. Scottish wind was calculated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

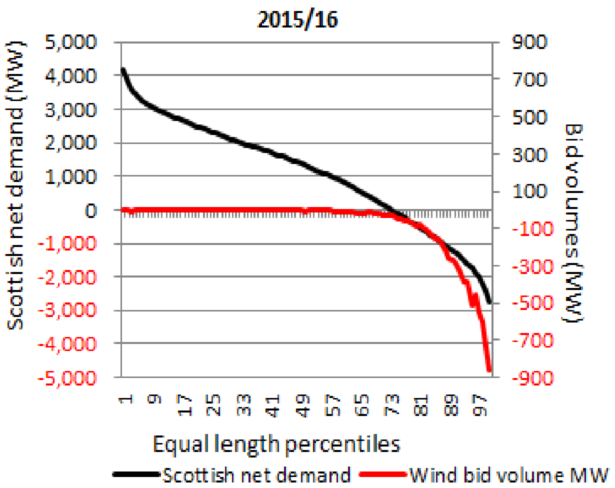
Scottish net demand is closely correlated with constraint cost

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.

[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

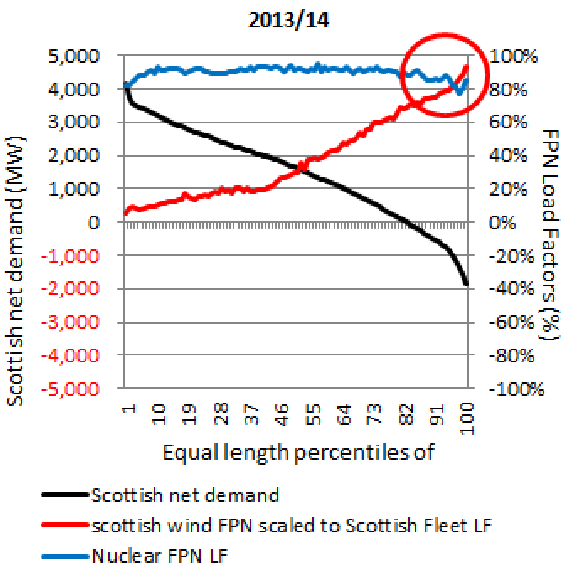

2013/14
Scottish net demand
Bid volumes (MW)
Equal length percentiles
Scottish net demand
Wind bid volume MW

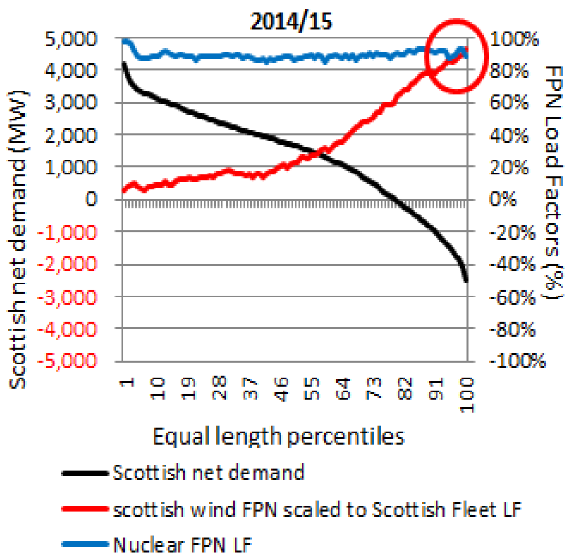

2014/15
Scottish net demand
Bid volumes (MW)
Equal length percentiles
Scottish net demand
Wind bid volume MW

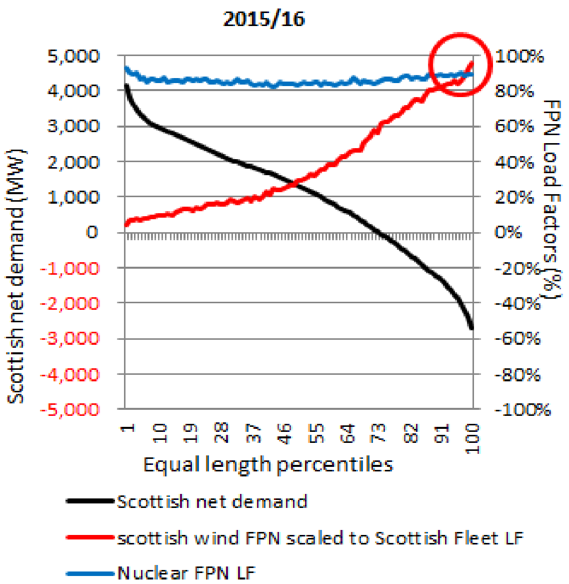

2015/16
Scottish net demand (MW)
Bid volumes (MW)
Equal length percentiles
Scottish net demand
Wind bid volume MW

Low Carbon generation <u>correlated</u> 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.



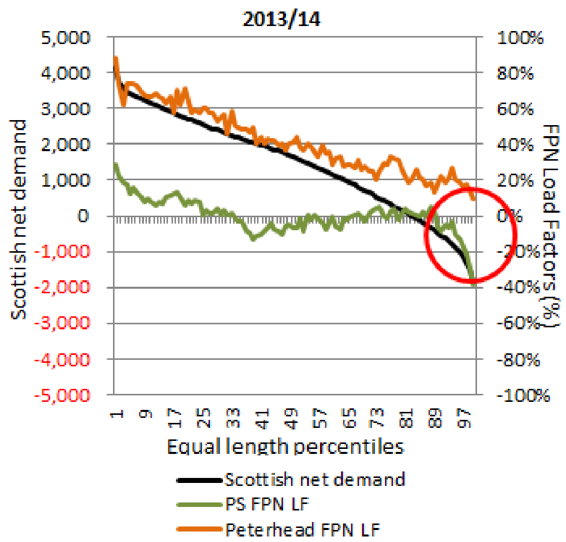


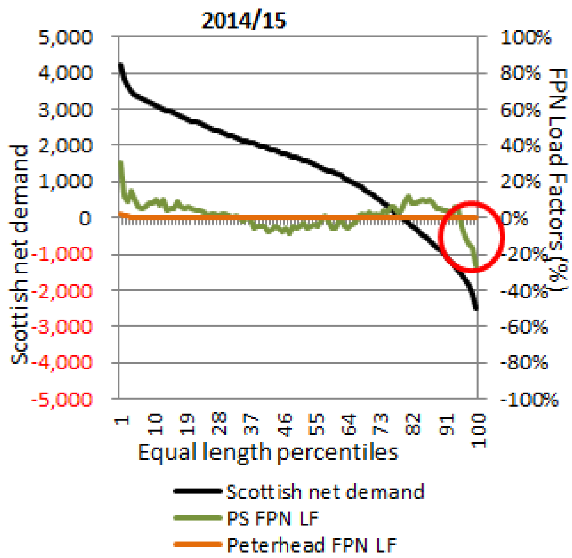


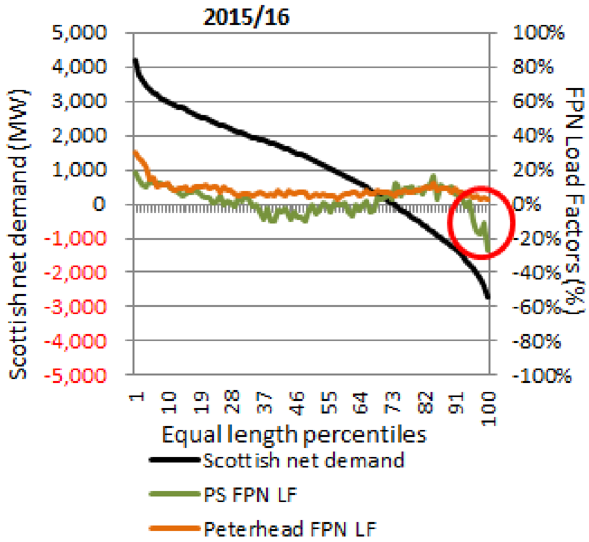
Marginal Conventional Carbon generation is <u>inversely</u> correlated with periods of constraint

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.







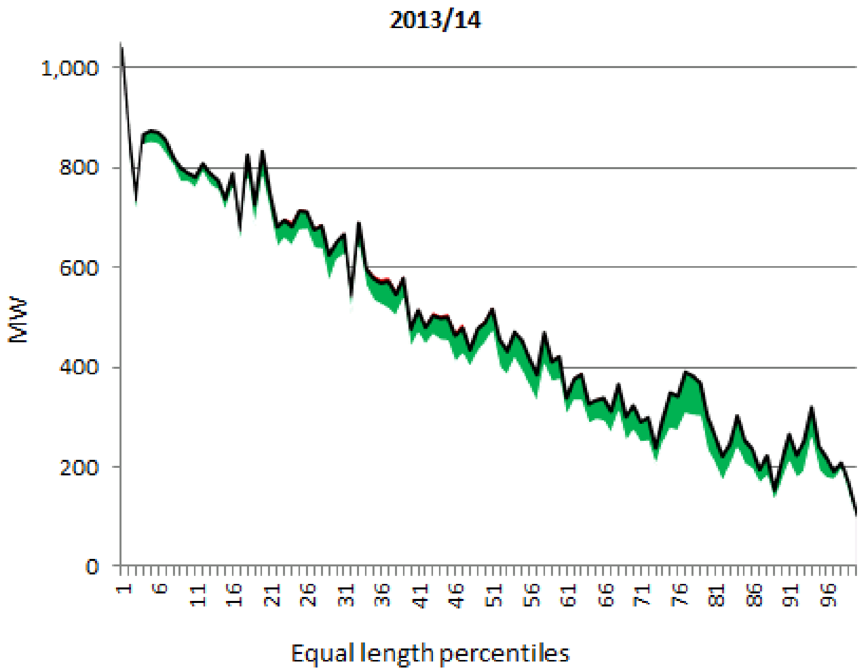
4.80 A Workgroup member stated that Peterhead is generating in the graphs and as such it cannot be suggested that they would not be contributing at all to constraints. The proposer agreed and explained that Peterhead would continue to make some contribution to causing constraint cost and that Peterhead 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

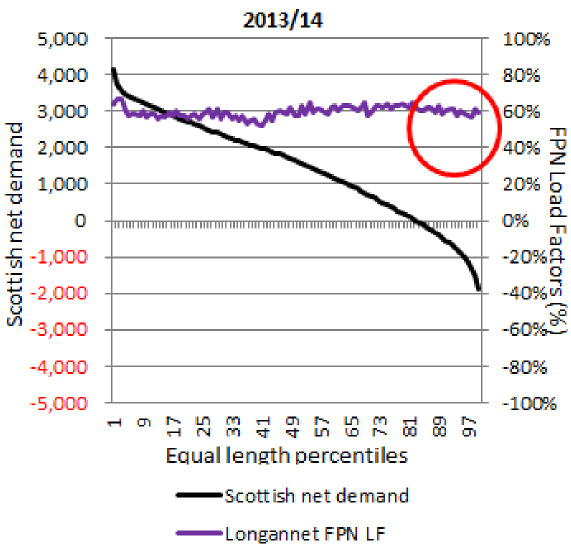
4.84 The graphs below illustrate Longannet FPNs compared with the volume of Bids and Offers which were taken. These results shown further support the proposed CMP268 approach of applying Conventional Carbon generator's ALF to their Not Shared Year Round tariff instead of the 100% used within the Baseline.

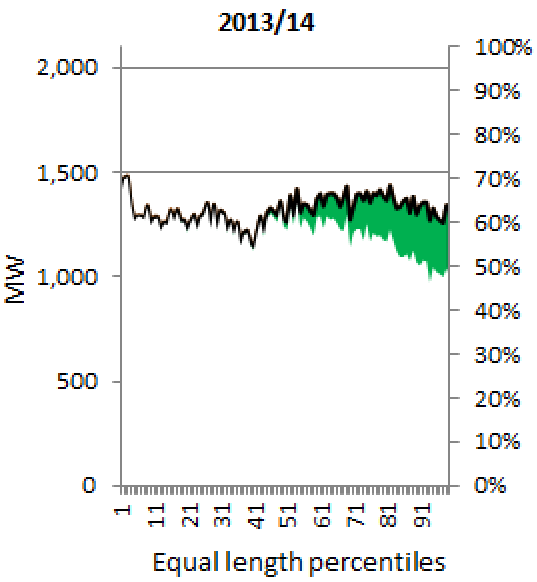
4.85 The volume of Bids taken (reduced output) are shown in the green shaded area. The volume of Offers taken to increase output are shown in the red shaded areas, note this it is difficult to see these volumes on the graph because the volumes were relatively small.

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.

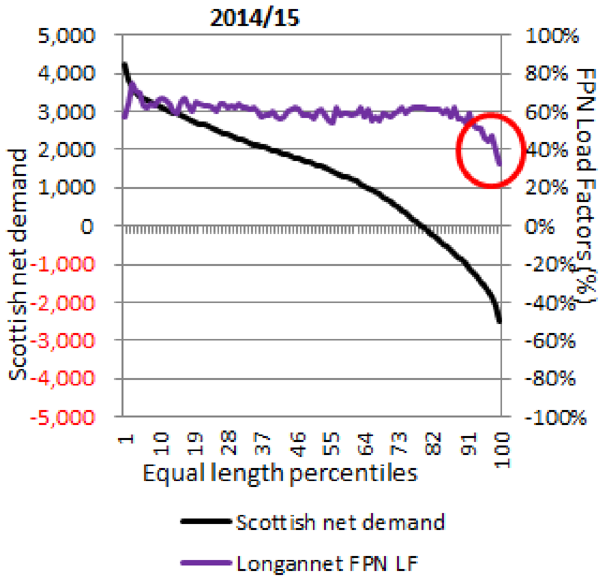
4.87 Further the analysis shows the average bid volume during those periods tended to reduce Longannet's generation load factor further by up to 20% compared with its FPN. The proposer stated that this is an illustration of periods when Longannet could be bid off at a relatively low cost (compared with 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.

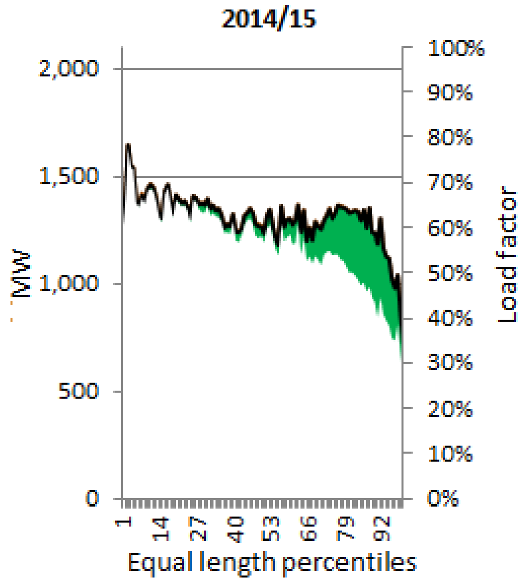
4.88 The proposer stated that it would appear that the generation output of Longannet after bids had been taken tended to be higher than that for Peterhead (30% to 50% for Longannet, compared with 0% to 20% for Peterhead), so it may be concluded that the operational characteristics of Longannet tended 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.

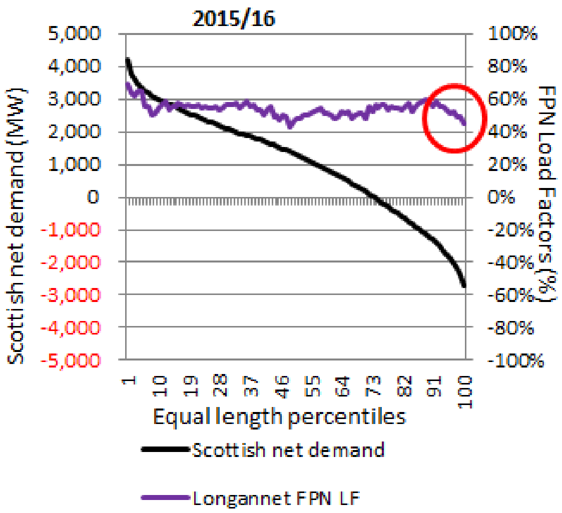




[14] Annual Load Factors for 2016/17 Generation TNUoS Charges, National Grid January 2016 http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/


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

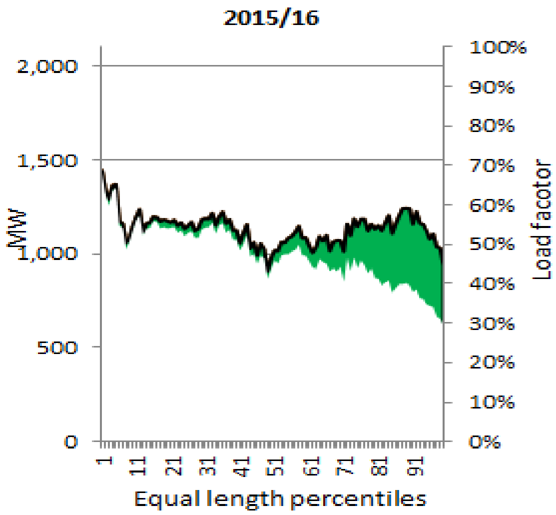

2015/16
MW
Load factor
Equal length percentiles

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

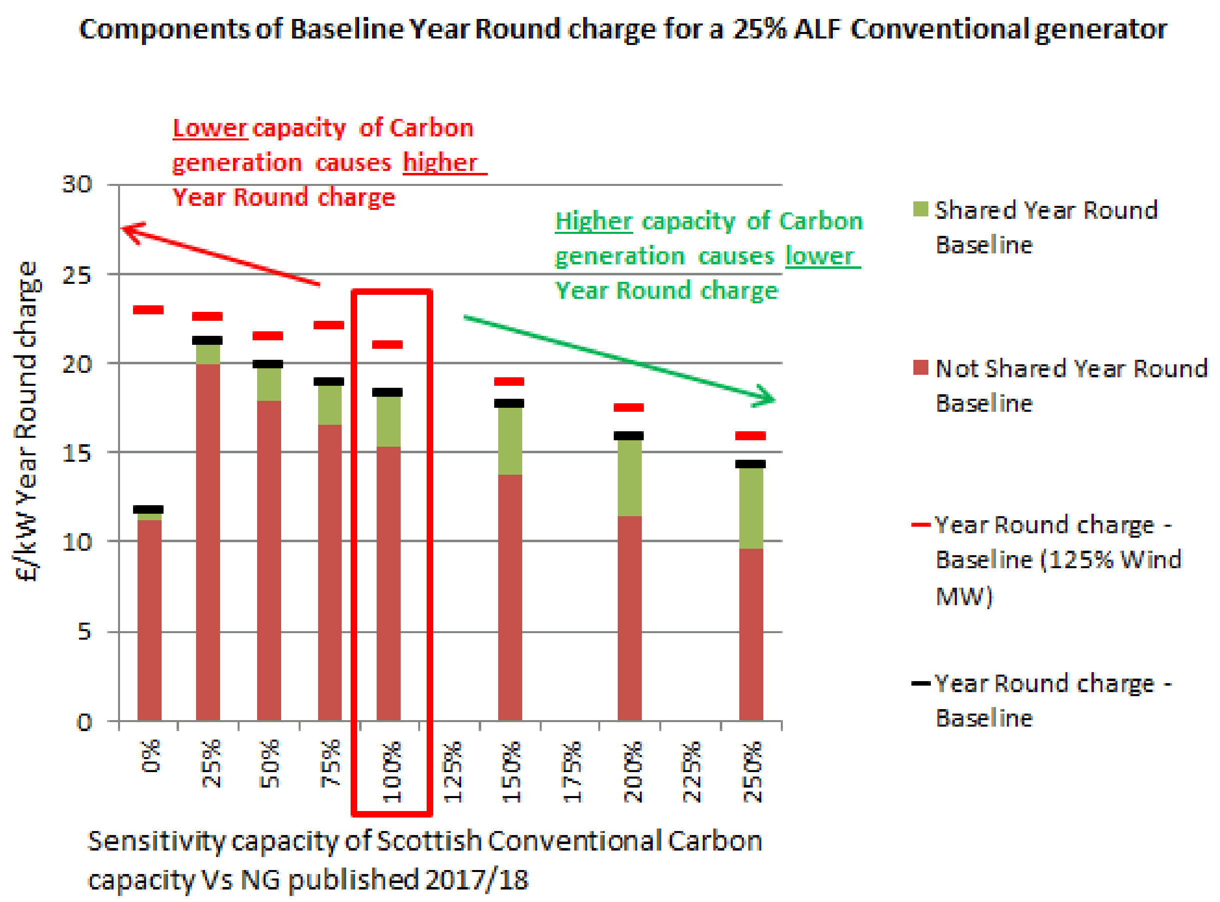
Baseline treatment of Not Shared Year Round tariff element causes a feedback loop

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.

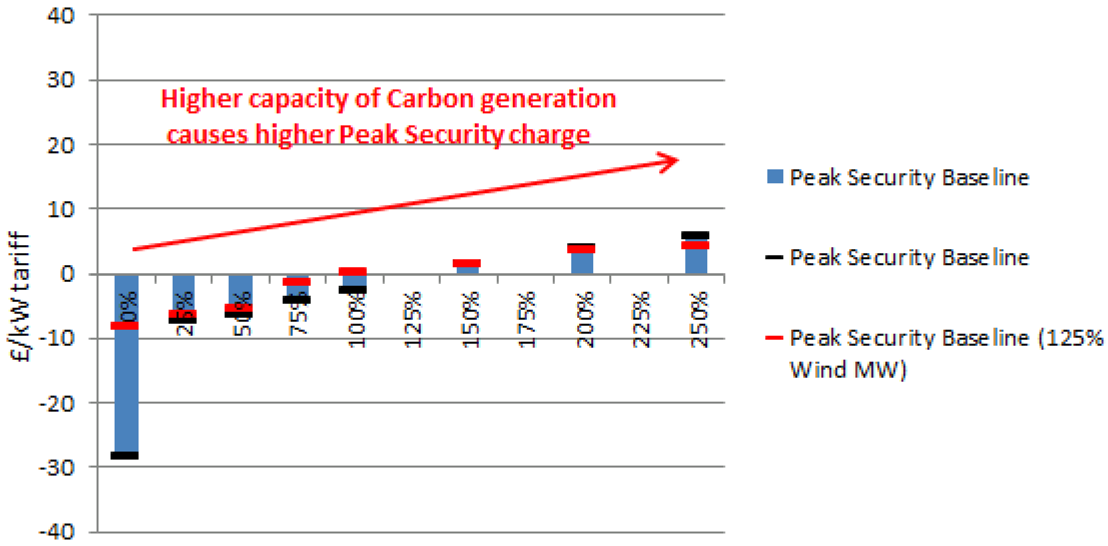


4.94 A Workgroup member noted that should plant close in a certain area that this would not necessarily mean that this would give a signal for other plant to close in the same area simply due to an increase in tariffs caused by the diversity calculation in the charging methodology. He went onto explain 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.

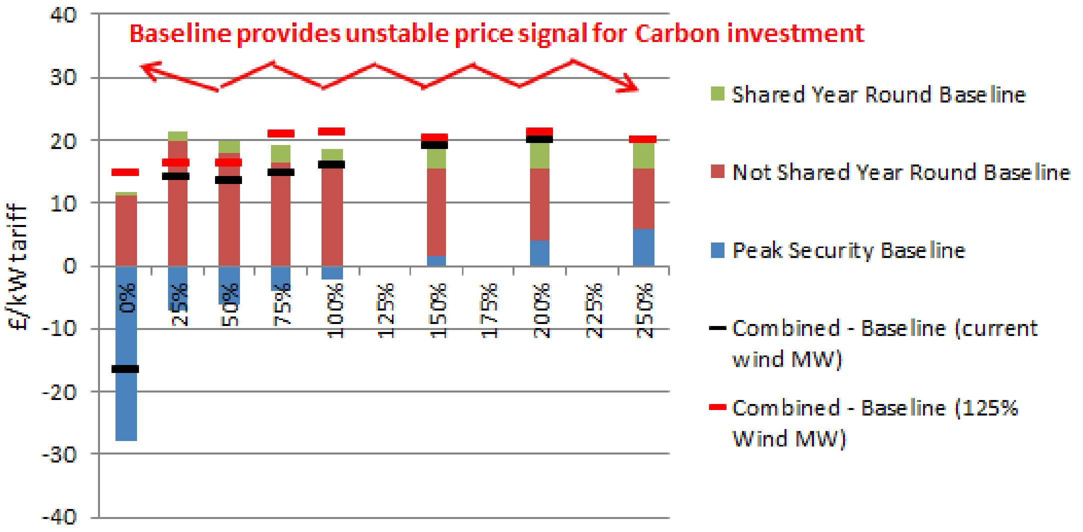
Baseline Peak Security tariff tends to provide opposite price signal to Baseline Year Round

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:

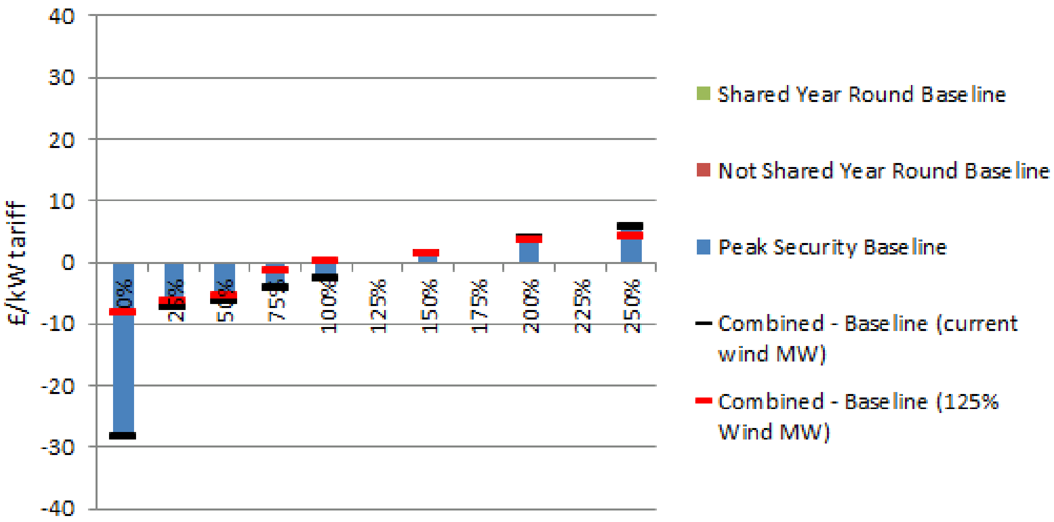
1. **Price signals tend towards equilibrium –** In contrast to the Baseline charging methodology, the set of price incentives provided by CMP268 do tend towards an economic equilibrium. This occurs because the transmission price signal for Conventional Carbon generators in Scotland tends to become more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

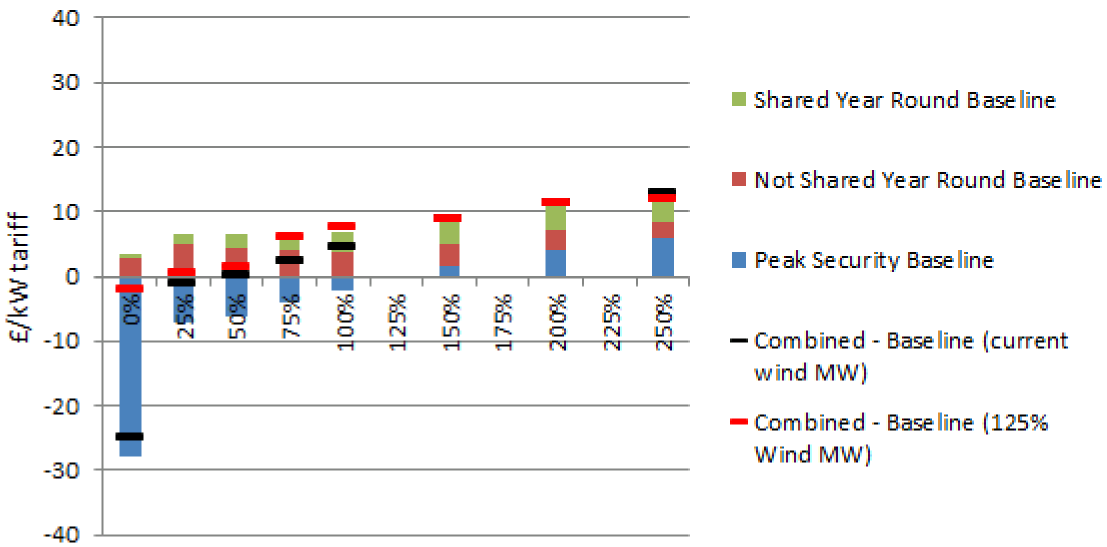
   b. **For a 25% ALF generator** – The price signal it receives is a balance of the Peak Security and Year Round tariffs. The proposer felt that this appropriately demonstrates that if the capacity of Conventional Carbon generation in Scotland reduced, then the negative Peak Security price signal would 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.

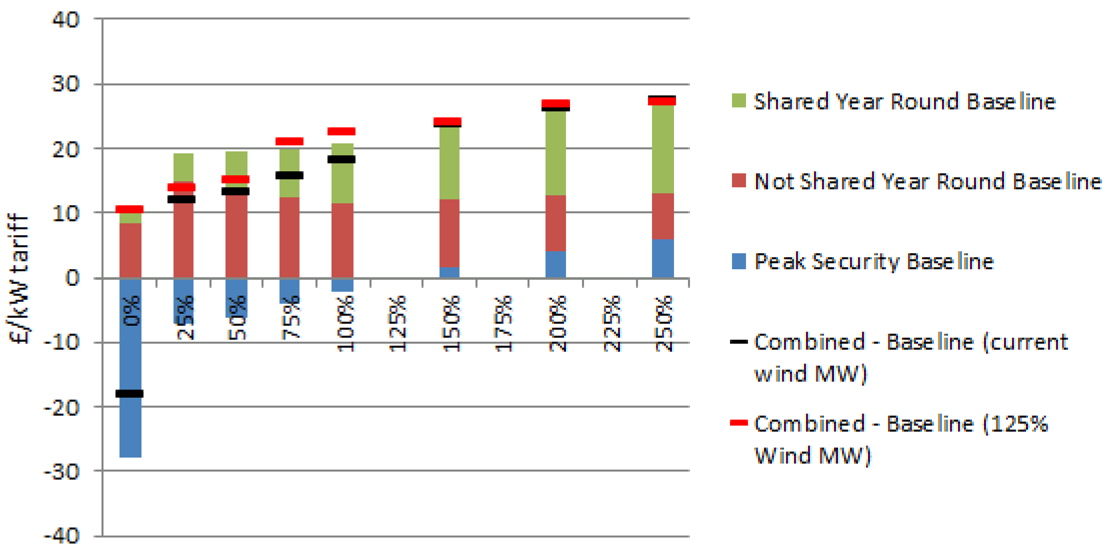
CMP268 - 0% ALF



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.

Costs

Code administration costs	
Resource costs	**£9,075** - 5 Workgroup meetings **£182** - Catering
Total Code Administrator costs	**£9,257**

Industry costs	
Resource costs	**£32,670** – **5** Workgroup meetings **£9,983**– **2** Consultations • 5 Workgroup meetings • 6 Workgroup members • 1.5 man days effort per meeting • 1.5 man days effort per consultation response • 5.5 consultation respondents
Total Industry Costs	**£42,653**

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 CMP268 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 Code Administrator Consultation responses

The Code Administrator Consultation closed on 3rd November 2016 and received six responses. A summary of these responses can be found below; the full responses are included within Annex 8.

Respondent	Do you believe that CMP268 better facilitates the Applicable CUSC Objectives?	Do you support the proposed implementation approach?	Do you have any other comments?
Uniper	No. What it does do is to provide a specific subsidy to particular plant which does not reflect the basis on which investment is made on the network or the rationale behind why diversity was introduced as part of CMP213. Therefore, it is detrimental to competition in generation, through distorting the wholesale market and capacity market, frustrating objective a). It also reduces cost reflectivity, working against objective b).	No.	As well as the more in depth comments we made to the workgroup consultation, we have provided some further analysis in the attached document, attempting to address some of the deficiencies in the analysis provided by the proposer at a late stage in the workgroup consultation. This shows that the proposer's analysis is incorrect and that the real issue appears to be that there is a lag preventing the ALF for Peterhead from immediately reflecting its recent lower levels of running. This lag of course was an issue which was well known when CMP213 was assessed and implemented. It was also a solution which was vigorously defended by the proposer at the time.
SSE	Yes, as per our Workgroup consultation response, we believe that CMP268 Original better meets all of the applicable CUSC objectives	Yes, we support the proposed implementation approach for the reasons described in the Code Administrator Consultation report.	There are some comments within the full response which outline our responses to some of the specific issues raised by other respondents to the CMP268 Workgroup consultation, please see the fill response.
Dong Energy	No, we believe that CMP268 does not better facilitate the Applicable CUSC objectives. In our view CMP268 is negative on objectives (a) and (b) and neutral on objectives (c), (d) and (e).	No, we do not support the proposed implementation date. In our view the proposed implementation date undermines the predictability and certainty that is supposed to underpin the GB charging regime.	We are concerned that a modification with as significant and fundamental impact as CMP268 was raised as an urgent modification. The risks of having mods like CMP268

			raised in this manner are that there is insufficient time to both perform sufficient, robust, scrutinised analysis, and engage effectively with stakeholders and industry. This significantly increases the risks of unintended consequences and modifications that do not actually meet the CUSC objectives or Ofgem's statutory duties.
Drax Power	No, as per our workgroup consultation response, the workgroup had had insufficient time to properly assess the proposal due to the short timescale. We believe that CMP268 will adversely affect the Applicable CUSC Objectives (a), (b) and (c).	No, the timescale for this change is too short. The implementation period should be at least one full charging year for a change of this nature, i.e. to ensure efficient cost pass-through in the traded market.	No.
EDF Energy	No. We do not believe the proposal takes forward cost-reflectivity, 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, for which very good topical engineering reasons can be hypothecated, as shown empirically in citations from our evidence in the current workgroup report and in our last response.	No. 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.	No
Scottish Power	The proposal does not better facilitate Applicable Charging Objective (ACO) (b). Cost reflective charges facilitate efficient economic decisions and thereby effective competition. As it is not clear that CMP268 will deliver most cost reflective charges than the baseline it will therefore not better facilitate ACO (a). The proposal is neutral against ACOs (c), (d) and (e) and overall will not better meet the ACOs than the current baseline.	Whilst we do not support implementation of CMP268 we would support the proposed implementation approach.	The evidence presented by the proposer appears to indicate that the particular class of generators identified as "Conventional Carbon", the Charging Methodology may not be fully cost reflective and that the issue would merit further examination and analysis that the workgroup was unable to pursue due to time constraints.

9 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 dictated the fact that they had 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 Workgroup to do so.

8.3 One Workgroup member stated that should this 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 the restrictions felt due to timescales of the modification in some Workgroup member's comments at various points throughout the report.

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 comments as to why they had voted as above. The following commentary was received 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. By 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 <u>**avoid**</u> 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 a 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 types.

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

<u>CUSC Panel Recommendation Vote</u>

8.6 The CUSC Panel met on 15 November 2016 and voted on the Original Proposal.

8.7 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 accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence 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; and

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

8.8 At the CUSC Modification Panel meeting on 15^{th} November 2016, the Panel voted on the CMP268 Original against the Applicable CUSC Objectives. Kyle Martin was absent from the meeting and passed on his voting rights to Garth Graham and Cem Suleyman was absent from the meeting and passed on his voting rights to James Anderson. The Panel agreed by majority that the Baseline better facilitates the Applicable CUSC Objectives.

<u>Vote 1</u> – does the Original Proposal facilitate the Objectives better than the Baseline?

Panel Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
	James Anderson					
Original	No	No	Neutral	Neutral	Neutral	No
	Voting Statement: Without a detailed re-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 behind a transmission boundary, 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. Therefore the proposal does not better facilitate Applicable Charging Objective (ACO) (b). Cost reflective charges 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 ACO (a). The proposal is neutral against ACOs (c), (d) and (e) and overall will not better meet the ACOs than the current baseline.					
	Bob Brown					
Original	No	No	Neutral	Neutral	Neutral	No
	Voting Statement: Insufficient time to allow evidence based decisions to be taken based on independent analysis.					
	Kyle Martin					
Original	No	No	Neutral	Neutral	No	No
	Voting Statement: The proposed solution does not clearly show that competition or cost reflectivity would be improved as a result of CMP268 being implemented. Therefore the original does not better facilitate CUSC objectives (a) or (b). The original is neutral against (c) and (d). Although the additional complexity is small, this this would not facilitate objective (e).					
	Garth Graham					
Original	Yes	Yes	Neutral	Neutral	Neutral	Yes
	Voting Statement: With respect to Applicable Objective (a) it is clear that this proposal will better facilitate competition in the generation and supply of electricity. The primary reason for this is because it will ensure that the cost reflectivity of transmission charges is improved, by correcting the defect identified in the proposal. By charging cost reflectively this will ensure that all Users operate equally in the competitive market, rather than, for example, some Users facing charges which, by them not being cost reflective, are either more expensive on the one hand or (for other Users) cheaper than they should be. With respect to Applicable Objective (b) it is clear that this proposal has, at its core, the improvement of the cost reflectivity of GB transmission charges. In particular, as the proposer has identified, this will better reflect sharing characteristics; better reflect operating characteristics of different Conventional Carbon generators; better enable a negative Peak Security tariff to provide a more effective economic price signal; better reflect cost with regard to generators in negative Year-Round Not-Shared zones; and the locational tariffs of other generator types are not affected. These attributes, both individually and collectively, are beneficial improvements to the CUSC baseline in terms of cost reflectivity. With respect to Applicable Objectives (c), (d) and (e), this					

	proposal is neutral in my view.					
	Nikki Jamieson					
Original	No	No	Neutral	Neutral	No	No
	Voting Statement: Effective competition derives from users making efficient economic decisions on their costs. It is not clear from the limited evidence provided and timescales to assess the modification that this improves the cost reflectivity for all users therefore improves on the current baseline. In relation to cost reflectivity, if Conventional Carbon does not contribute to reinforcements in areas with a lack of diversity of Generation, as implied by the defect in the modification, then Load Factor should not be applied to the Year Round Not Shared element of the tariff for Conventional Carbon. By applying Load Factor it indicates that this type of Generation does contribute to reinforcements. In zones with limited diversity the reinforcements would therefore be based on total capacity as it is under the current methodology. Therefore using Load Factor does not seem appropriate. Finally it is not clear that this modification does not create any unintended consequences which will require further modifications.					
	Paul Jones					
Original	No	No	Neutral	Neutral	Neutral	No
	Voting Statement: The assessment of CMP213 involved a lot of work to illustrate the link between a plant's load factor and constraint costs on the system (and therefore by implication investment costs). This relationship was shown to break down in areas of low diversity. The CMP213 workgroup did not conclude that this only held for low carbon plant, as the solution developed was to reduce the ALF related asset costs for all plant. Otherwise it would have looked like CMP268. The evidence from the CMP213 report backs this up. The incentives from the current methodology reflect this. When diversity increases, the cost per kW of plant in that area is affected to reflect the increased effective sharing which can take place. Diversity does not provide a signal to close and reduce diversity as has been suggested. It may have that result in one or two circumstances, but this would be driven by the plant's position on the system and perhaps its ALF, as well as other factors such as a plant's efficiency and reliability. The diversity part of the signal is acting as intended. The proposer believes that high carbon plant will always result in low constraint costs and therefore the baseline is not correct. This is not proven and indeed in the past we have had very high constraint costs on congested borders driven by the actions of both low and high carbon plant. It also isn't what CMP213 concluded. There has been conflicting analysis about whether the baseline or CMP268 would produce results closer to those which would result from using SQSS scaling factors. That carried out using actual ALFs rather than hypothetical ones shows that the baseline is closer. It also shows that CMP268 would produce large drops in charge for a handful of stations which are far below the SQSS derived charges. This would indeed only result in a small increase in the charges for everyone else, but in relative competitiveness terms it is very significant, especially when there is an upcoming capacity market auction. There is no evidence that this change would be more cost reflective than the baseline, and indeed CMP268 appears to be worse than the baseline against objective b). Given the relative competitiveness effects as a result, this would distort competition and therefore					

<table>
<tr><td></td><td colspan="6">act against objective a) too.</td></tr>
<tr><td></td><td colspan="6">Simon Lord</td></tr>
<tr><td>Original</td><td>No</td><td>No</td><td>No</td><td>Neutral</td><td>Neutral</td><td>No</td></tr>
<tr><td></td><td colspan="6">Voting Statement: The non- shared element of the transmission tariff represents the minimum size of the boundary that must be built to accommodate the maximum level of sharing. The full cost of this minimum boundary size should be targeted onto users behind the boundary. This is the principle behind the sharing element of the TNUoS tariff developed as part of Transmit. Whilst there could be incremental changes the methodology used to allocate sharing this modification does not proposed changes to this area which would be need to be part of a wider reform package. This modification prosed to “reduce” the cost reflective signal by applying a load factor element to the non-shared element. Whilst it can be agreed that the non-shared element changes as different volumes of generation commits behind a boundary to apply a load factor element pre-judges this position and is not cost reflective. Both the theory and practical implementation of this modification are flawed and is evidenced in the working group report.</td></tr>
<tr><td></td><td colspan="6">Cem Suleyman</td></tr>
<tr><td>Original</td><td>No</td><td>No</td><td>Neutral</td><td>Neutral</td><td>Neutral</td><td>No</td></tr>
<tr><td></td><td colspan="6">Voting Statement: Based on the evidence presented in the Modification Report, there may be incremental improvements that could be made to better incorporate the concept of 'Sharing' into the TNUoS charging method. However, the evidence presented that CMP268 does better reflect the 'Sharing' concept in the TNUoS charging method is not compelling. In particular:
1) For the analysis based on SQSS scaling factors, It has not been explained why SQSS scaling factors are a benchmark for 'success'. As such this analysis does not appear to be relevant for the consideration of the merits of CMP268.
2) The use of FPN data to illustrate the correlation between generation dispatch and constraints is misleading particularly where plant is run for system security reasons e.g. voltage control.
3) The price of bids are determined by the level of competition in the BM not by the cost of service provision. As such, at times where there is a lack of conventional generation the price of bids are likely to rise reflecting the increased value of the service.
For these reasons I am not convinced that CMP268 is more cost reflective than the Baseline. Therefore I do not believe that CMP268 better facilitates ACO (b). Effective cost reflective signals will better facilitate effective competition. As CMP268 does not better facilitate ACO (b) it therefore does not better facilitate ACO (a). For these reasons I believe the Baseline is the best option.</td></tr>
<tr><td></td><td colspan="6">Paul Mott</td></tr>
<tr><td>Original</td><td>No</td><td>No</td><td>No</td><td>Neutral</td><td>Neutral</td><td>No</td></tr>
<tr><td></td><td colspan="6">Voting Statement: There was too little time available for an evidence-based decision to be made on re-opening CMP213 and its diversity method 1 (inherent within CMP213 WACM2) - a contrast for this mod, with 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 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</td></tr>
</table>

	carbon-based generation is left, is running, due to growing concerns over the national issue of inertia and frequency management, as well as relevant local system (voltage/stability) issues. CMP268 not being cost-reflective, it will be re-distributive in a manner that is unwarranted, and thus harmful to competition.

<u>Vote 2</u> – *Which option is the best?*

Panel Member	BEST Option?
James Anderson	**Baseline**
Bob Brown	**Baseline**
Kyle Martin	**Baseline**
Garth Graham	**Original**
Nikki Jamieson	**Baseline**
Paul Jones	**Baseline**
Simon Lord (Paul Jones)	**Baseline**
Cem Suleyman	**Baseline**
Paul Mott	**Baseline**

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

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.

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.

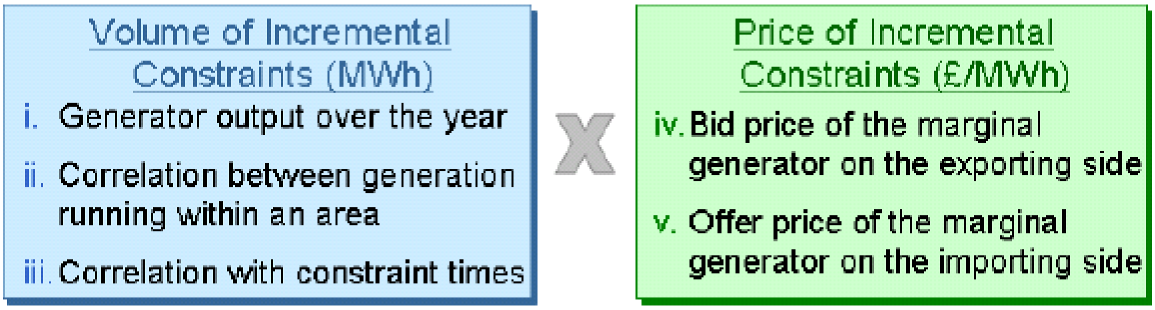
Detailed economic rationale behind the current methodology and this modification proposal

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]

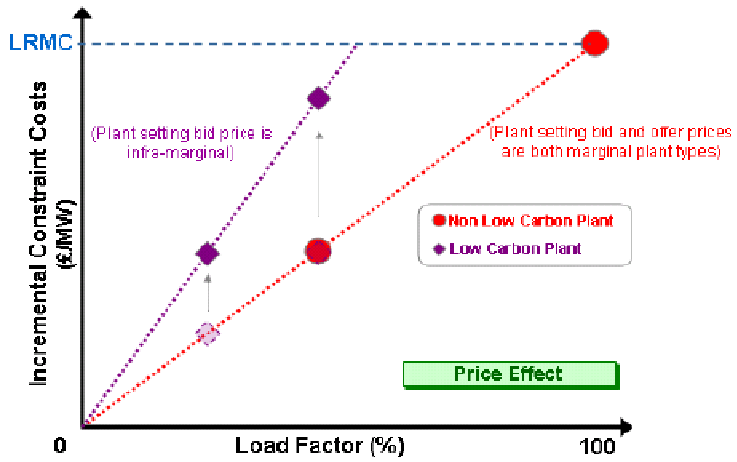


Figure 7 – Divergence in the linear relationship between low carbon and non low carbon plant

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>***

<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</u>." [emphasis added]

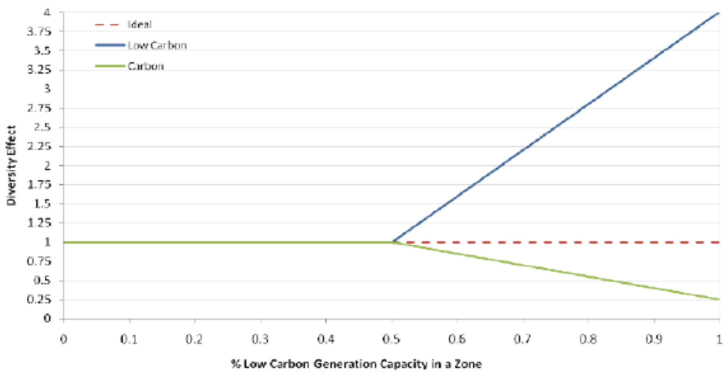


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

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.

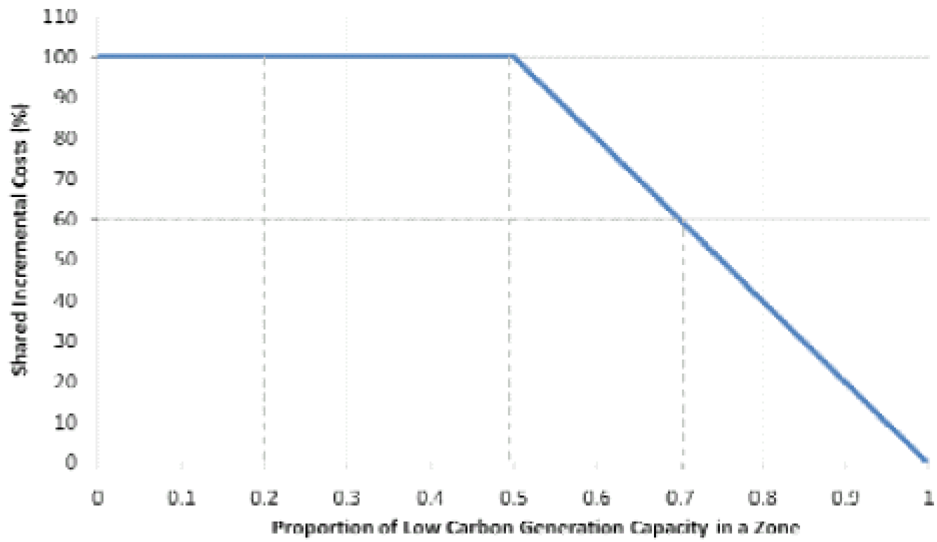
Description of the CUSC Modification Proposal

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.

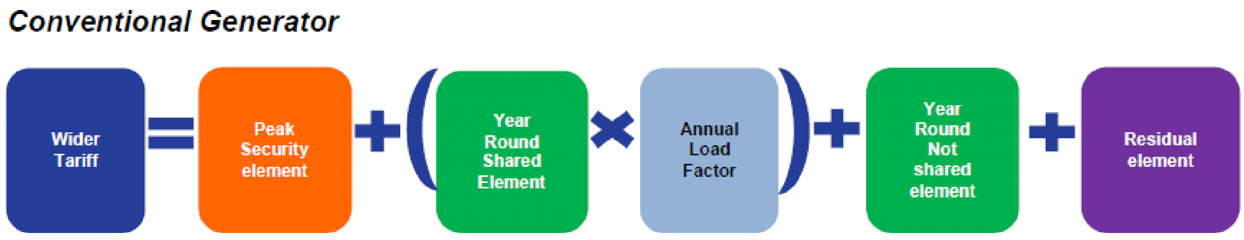
The element of the current tariff formula to be changed

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.

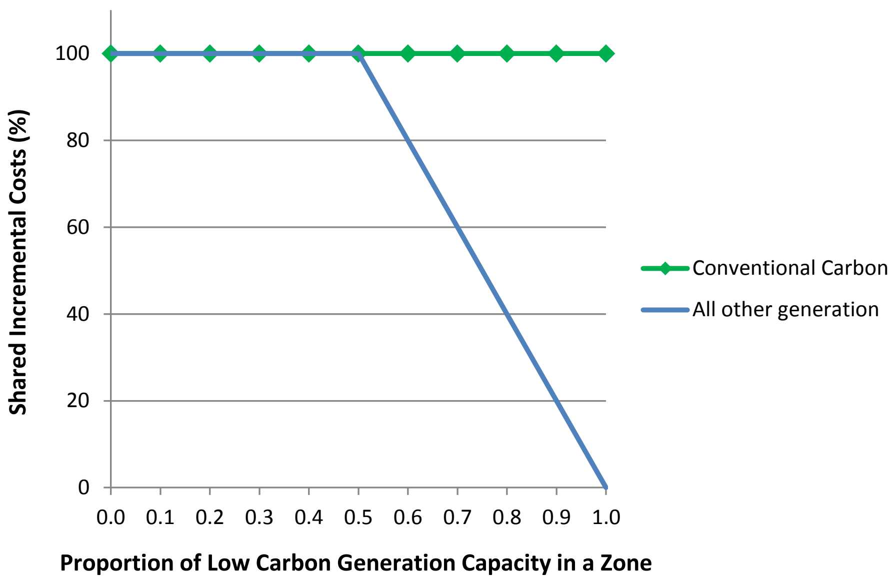


This principle is enacted through the current formula within the charging methodology where all generators (including Conventional Carbon generators) have their ALF applied to their Shared Year Round tariff element, but their ALF is not applied to their Not Shared Year Round tariff element. This is illustrated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



Proposed change to TNUoS tariff formula

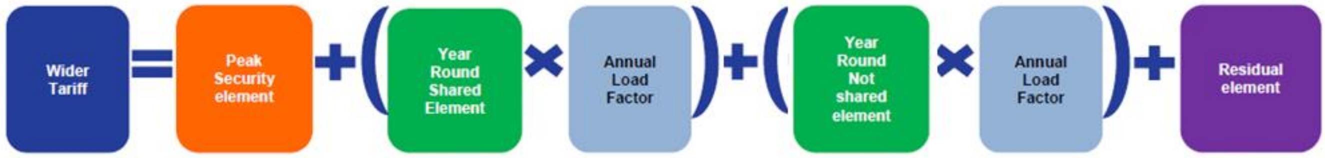
This modification proposes a change to the tariff formula relating to the way sharing is applied to Conventional Carbon generators so they continue to obtain 100% sharing of incremental costs irrespective of the proportion of low carbon generation capacity in a zone. This is illustrated by the graph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



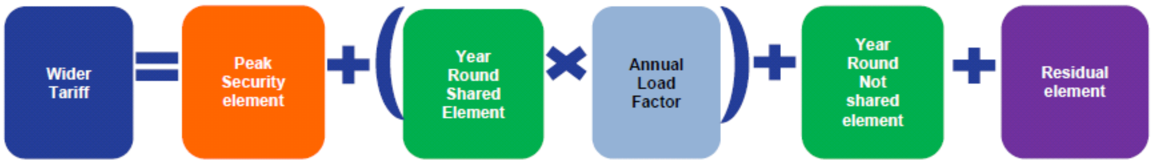
This modification proposal will recognise that even when the proportion of "Low Carbon" plant influencing a boundary is close to 100%, then any conventional carbon plant should have its ALF applied to the whole Year Round tariff (both Shared and Not-Shared elements of Year-Round).

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
23 November 2016	Final report sent to Authority for decision
2 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,
Reigate,
Surrey
RH2 9BU
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.

[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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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:	John Tindal 01738 457308 John.tindal@sse.com
Company Name:	*SSE*
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]

[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.

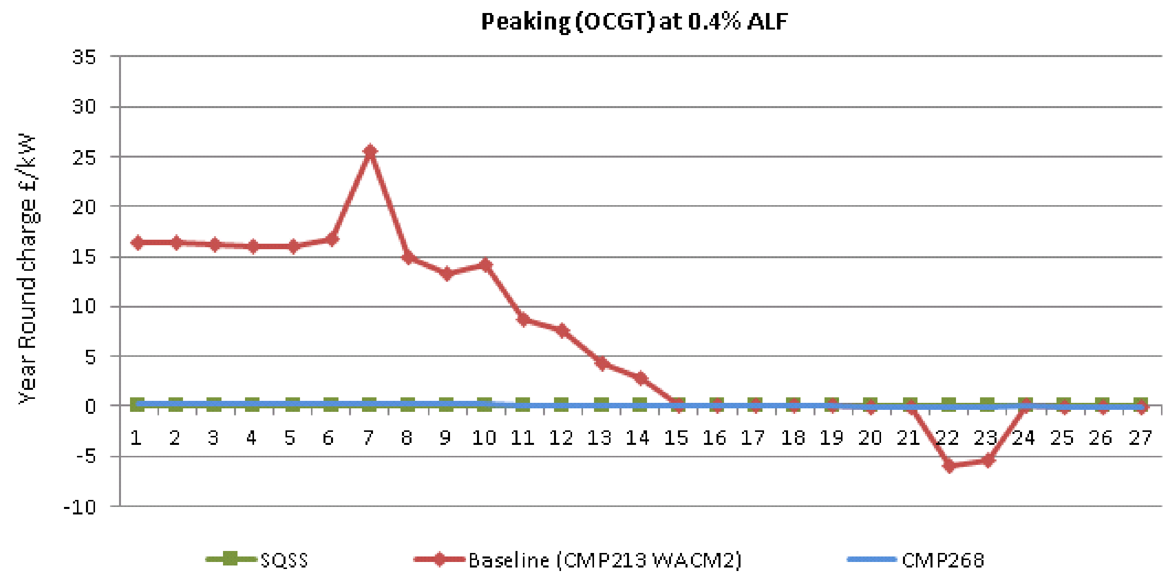
1.1. More cost reflective for Peaking (OCGT) generators

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

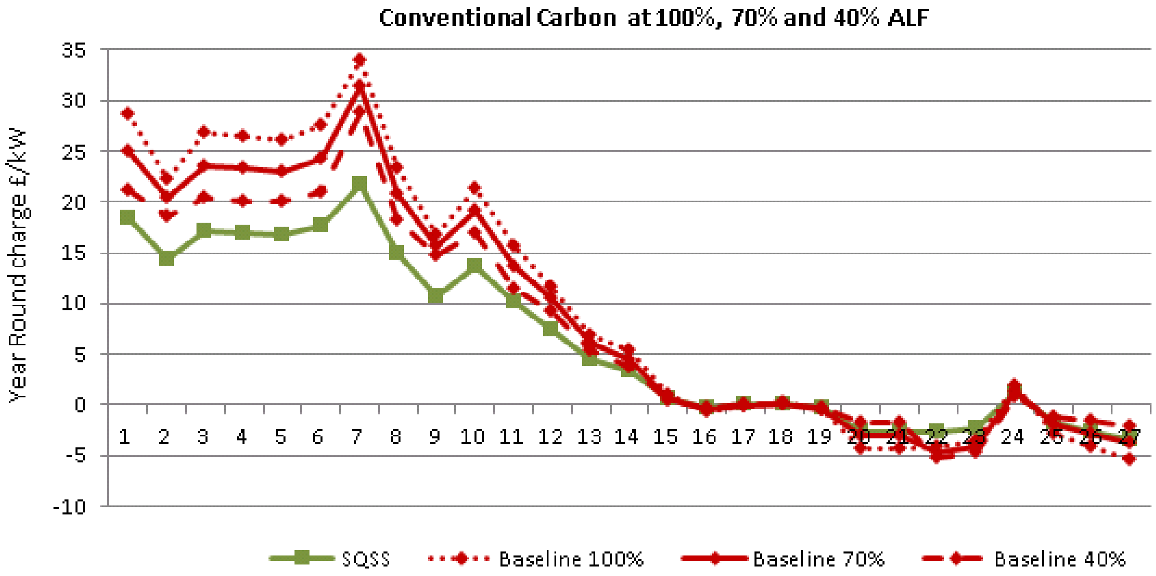
[4] CMP213 Final CUSC Modification Report Volume 1 http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP213/

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

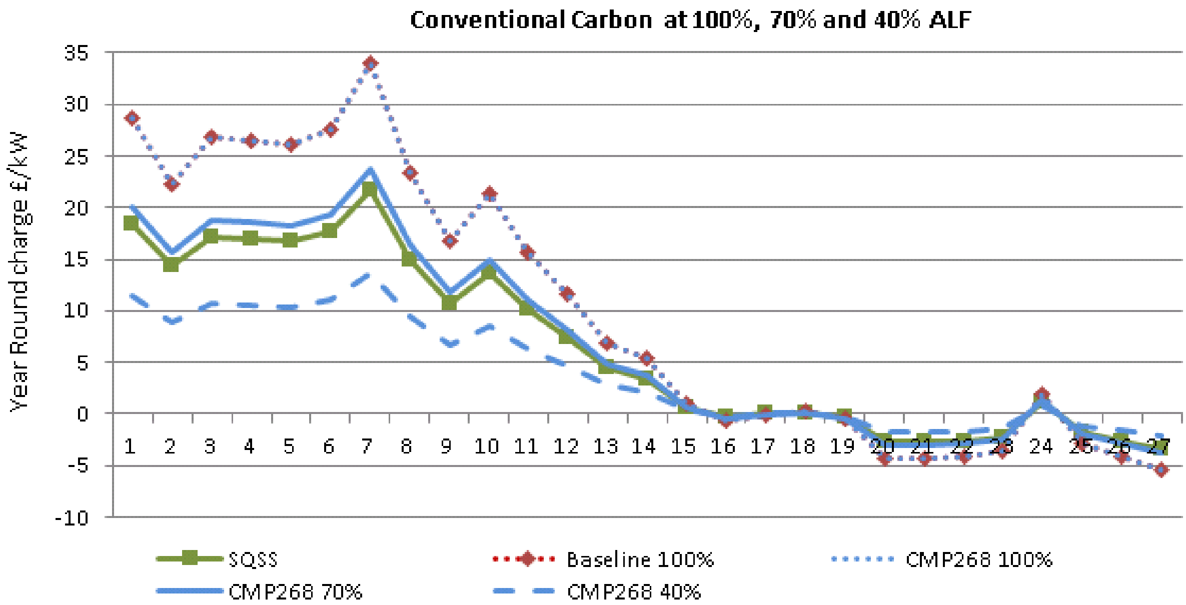
[6] Assessing the Cost Reflectivity of Alternative TNUoS Methodologies, NERA & Imperial College London, February 2014 http://www.nera.com/content/dam/nera/publications/2014/CostReflectivityReport.pdf

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.



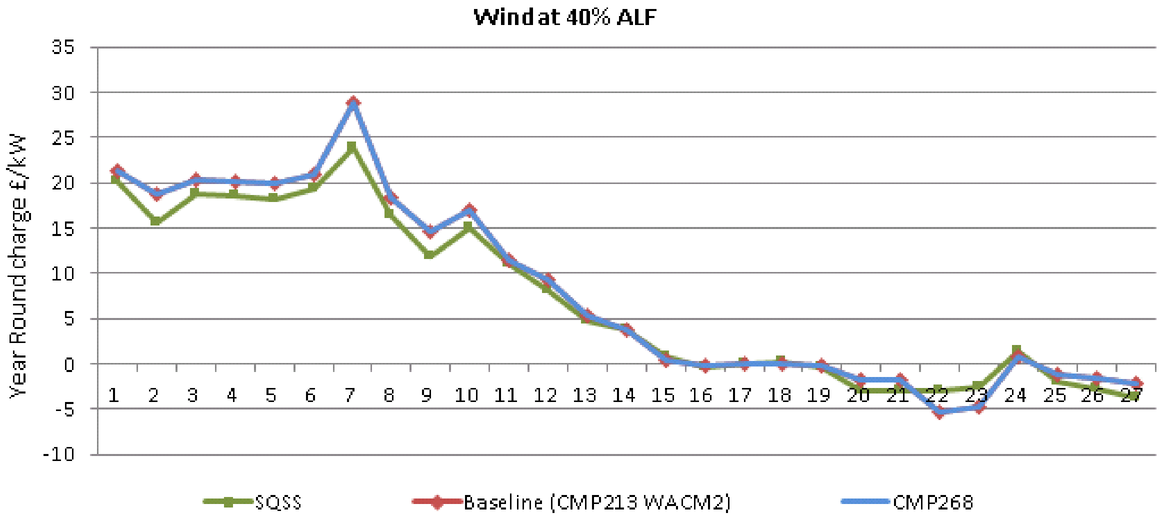
The graph below shows a similar set of tariffs derived from the CMP268 methodology from which three key conclusions can be drawn. Firstly, it shows that for a notional 100% ALF generator, CMP268 would provide a set of Year Round charges that are identical to the Baseline, therefore for a notional 100% 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.

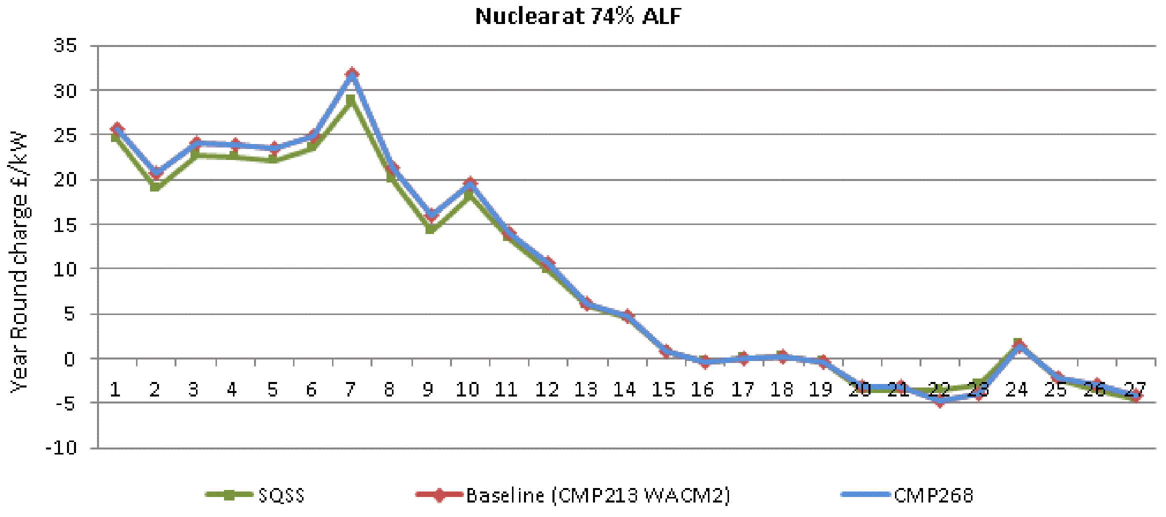


1.3. Equally cost reflective for Low Carbon generators (Wind and Nuclear)

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%

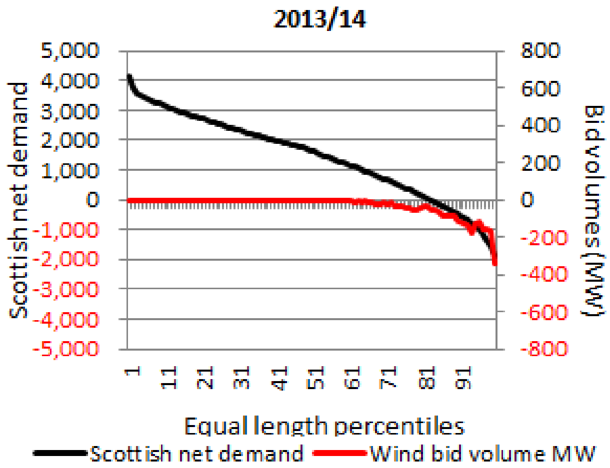
2. Empirical evidence that Conventional Carbon generators do tend to operate in a way which is consistent with CMP268

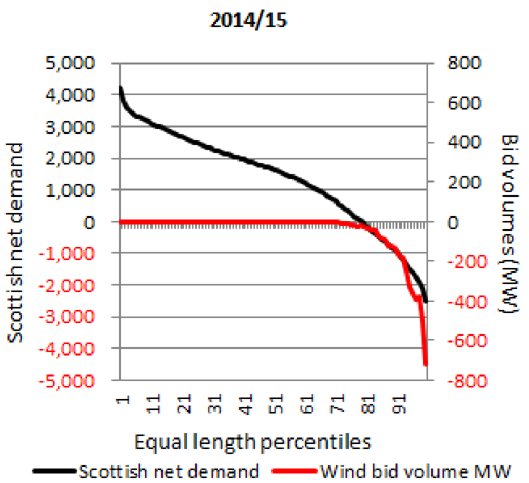
SSE carried out analysis comparing MWh volumes for FPNs, Bids and Offers for Conventional Carbon generators (CCGT and Pumped Hydro) in Scotland compared with net demand in the three financial years of 2013/14, 2014/15 and 2015/16. This analysis suggested that the historic operational characteristics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

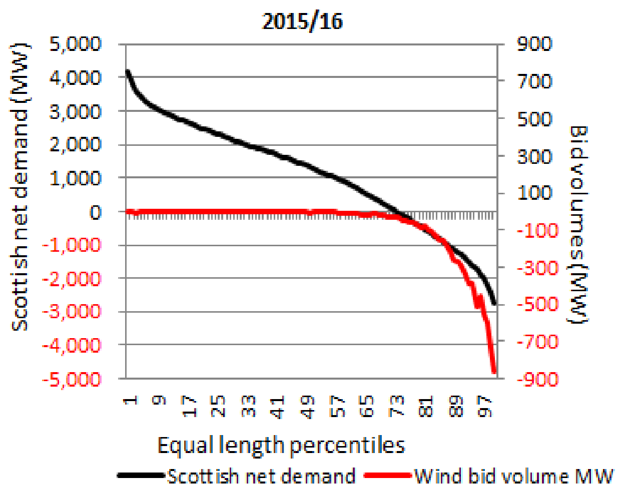
Scottish net demand was calculated as Scottish demand minus Scottish wind generation. This used National Grid published INDO demand, adding back in embedded wind, then applying a 9% pro-rata adjustment[7] to derive an equivalent figure for Scottish demand. Scottish wind was calculated from all transmission 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.







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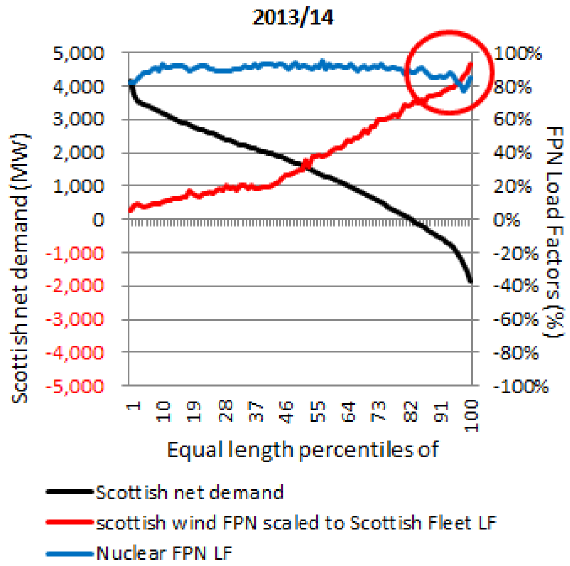
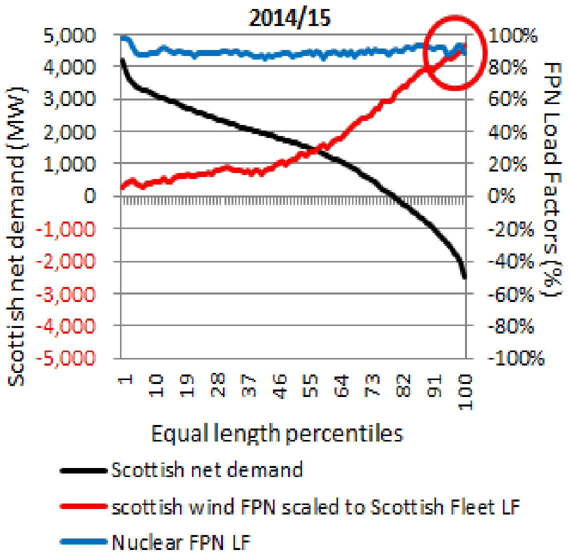
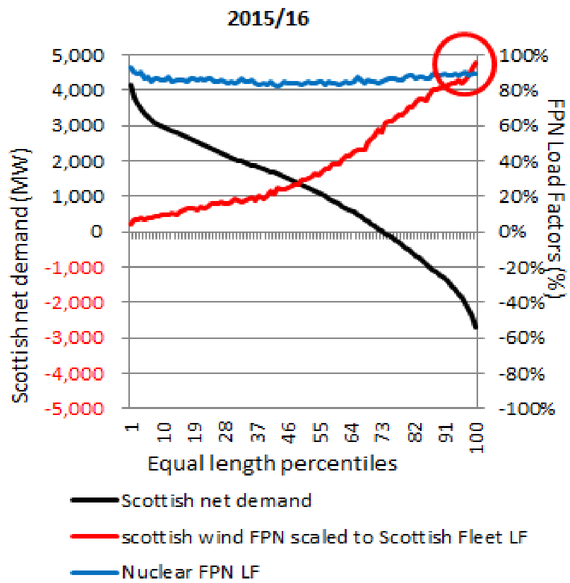
[7] Based on Ofgem published Renewables Obligation eligible demand for Scotland as a % of GB eligible demand https://www.ofgem.gov.uk/publications-and-updates/renewables-obligation-total-obligation-201516

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.



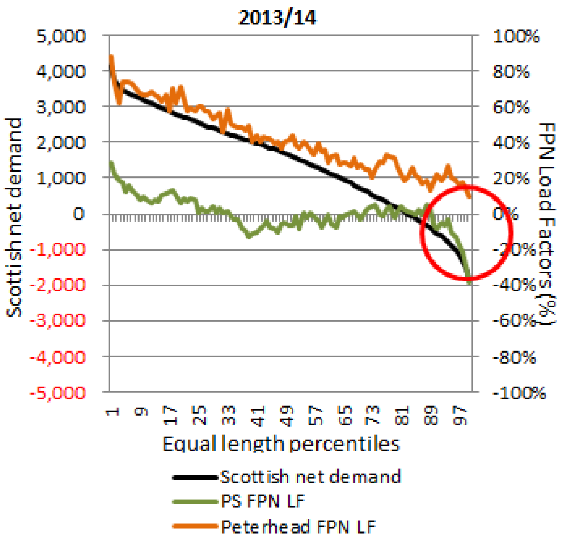


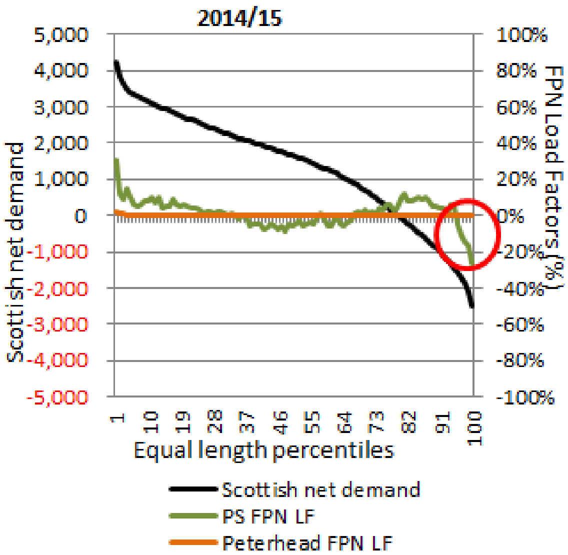


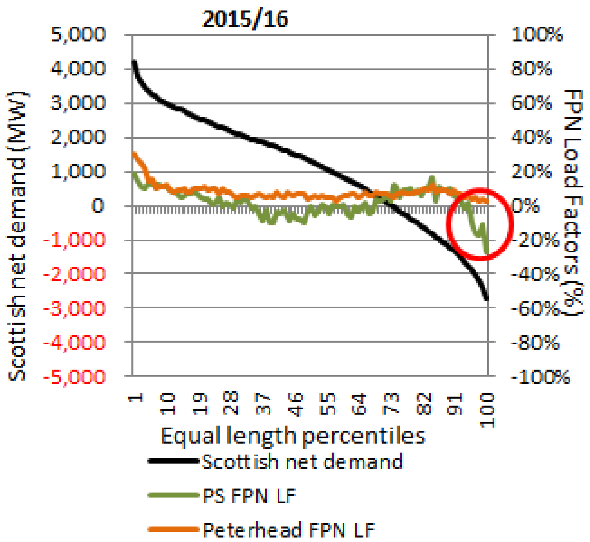
2.3. Marginal Conventional Carbon generation is inversely correlated with periods of constraint

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.

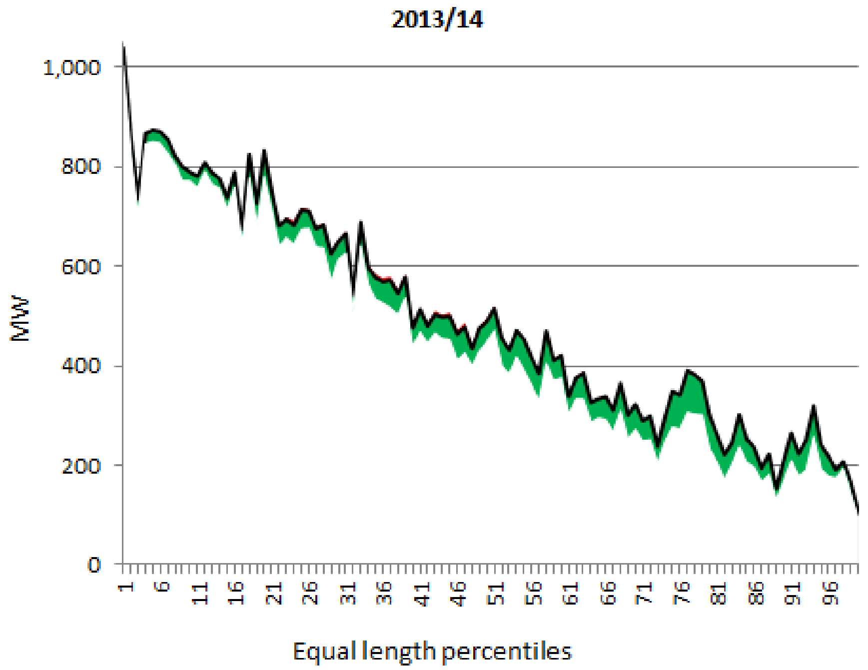






2.4. Marginal Conventional Carbon Generator (Peterhead) not being "Offered on"

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].

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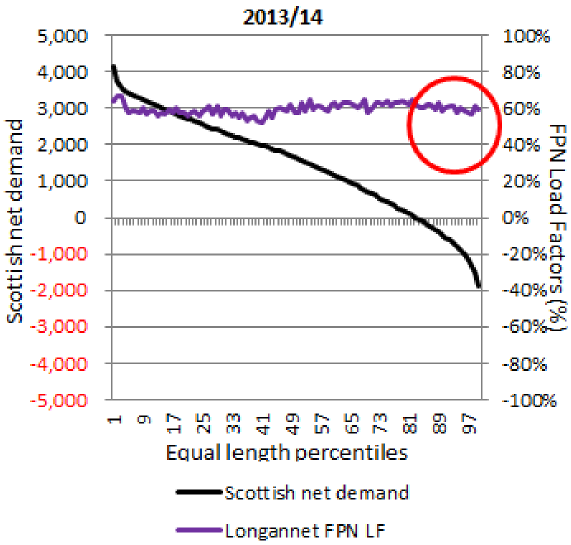
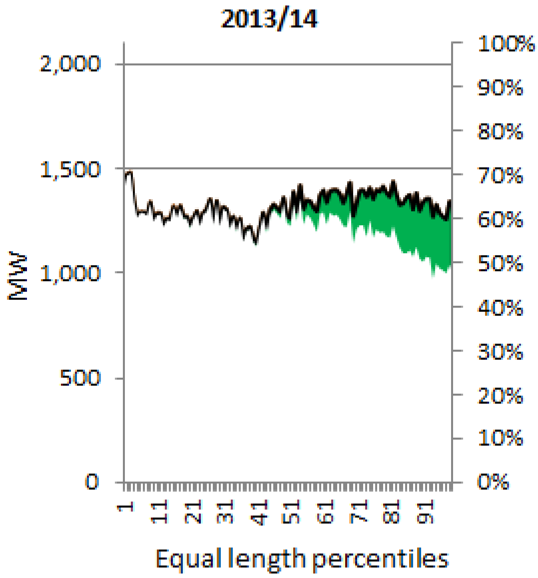
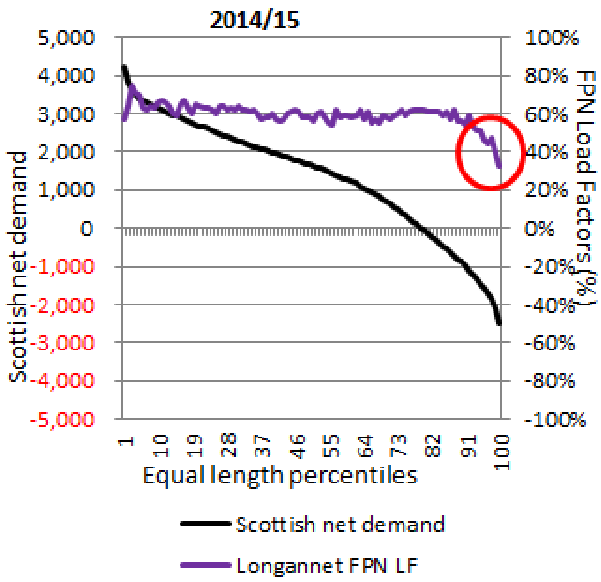
[8] Annual Load Factors for 2016/17 Generation TNUoS Charges, National Grid January 2016
http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/



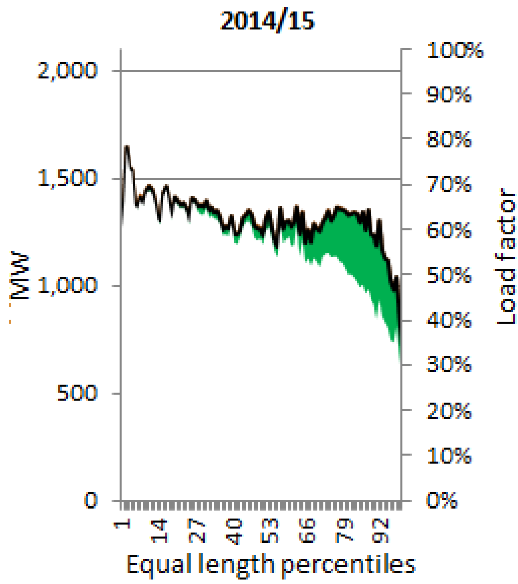
2013/14
Scottish net demand
FPN Load Factors (%)
Equal length percentiles
Scottish net demand
Longannet FPN LF



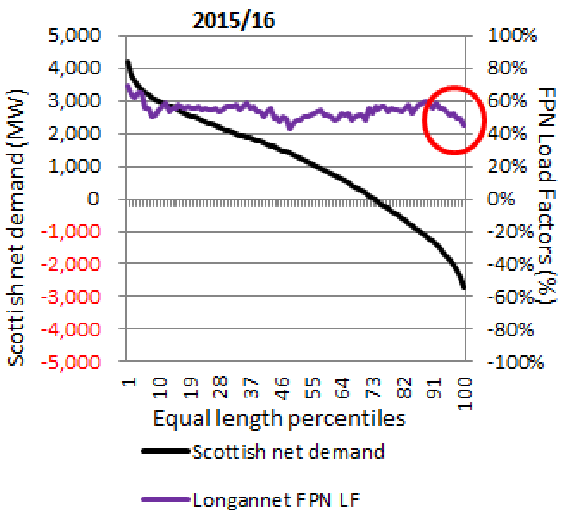
2013/14
MW
Equal length percentiles



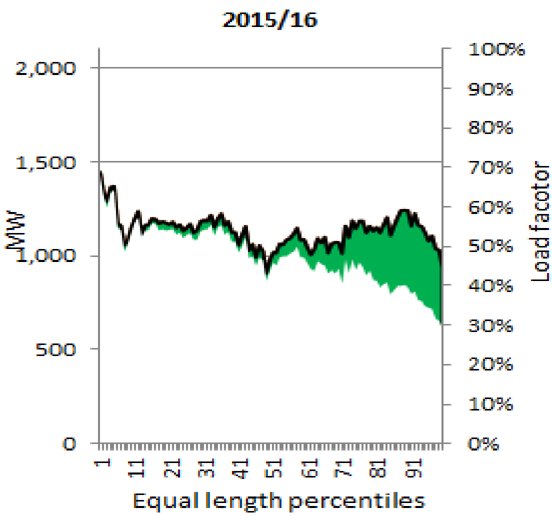
2014/15
Scottish net demand
FPN Load Factors (%)
Equal length percentiles
Scottish net demand
Longannet FPN LF



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 factor
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

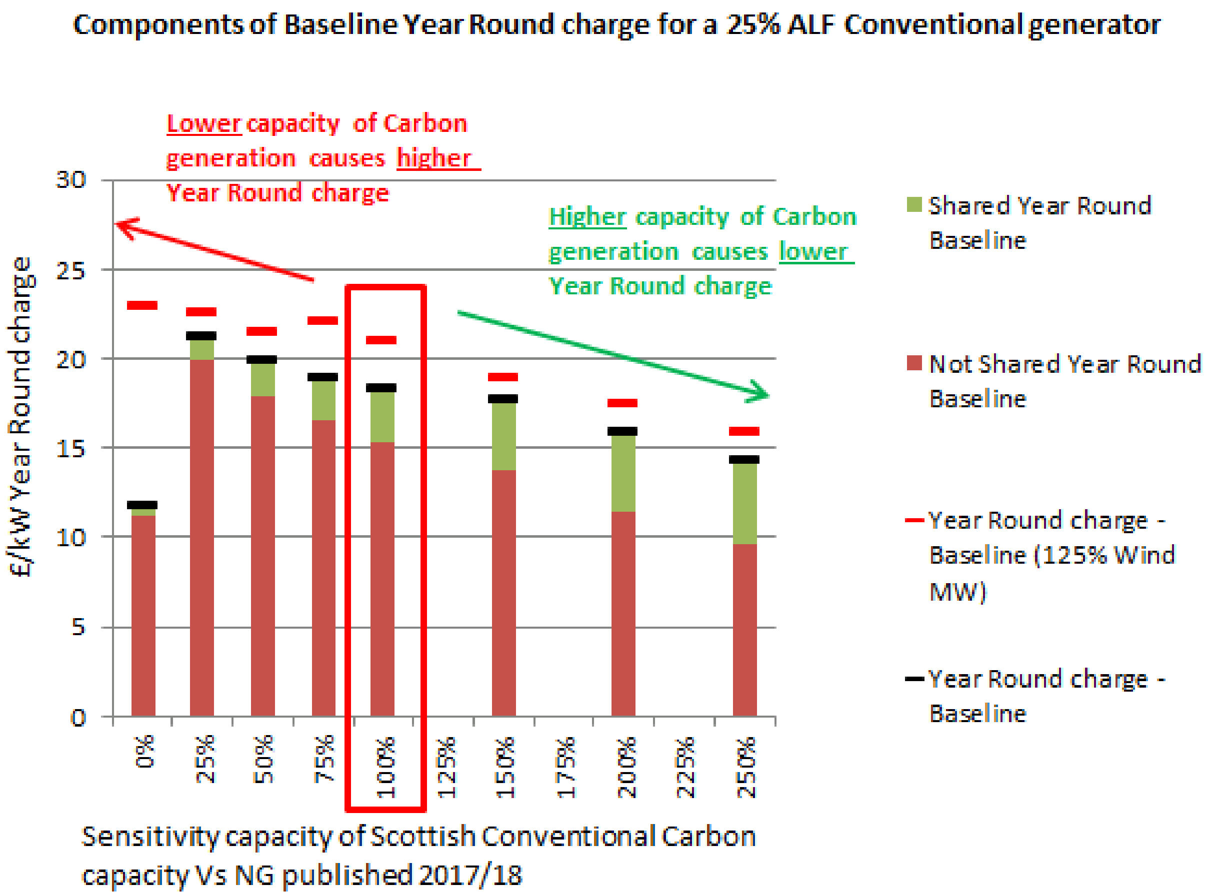
3.1. Baseline treatment of Not Shared Year Round tariff element causes a feedback loop

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.

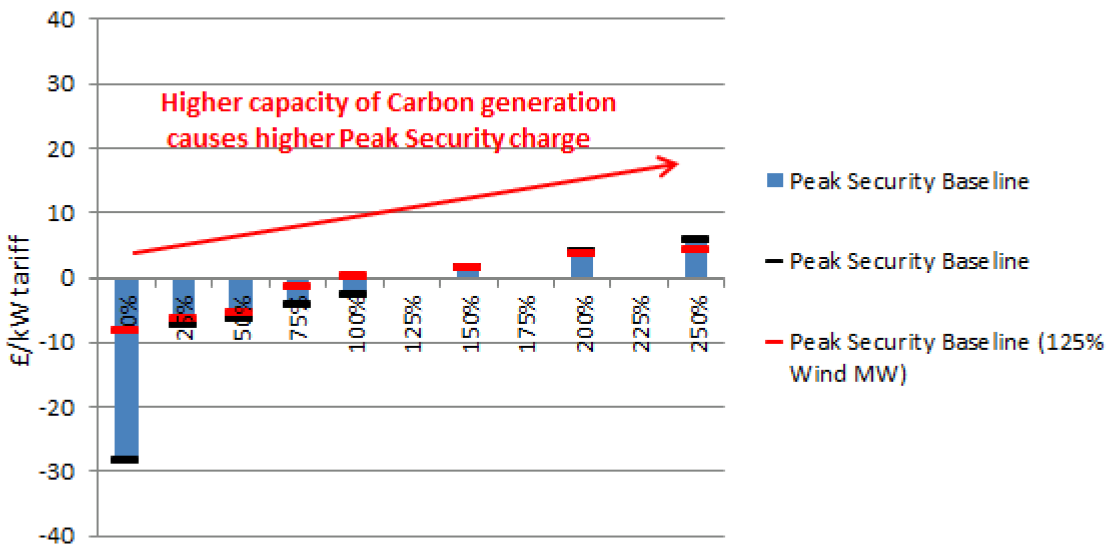
The horizontal red bars shows the same result, but using the additional sensitivity assumption of a 25% increase in the capacity of wind in Scotland. This sensitivity highlioghtes that with the additional weind capacity, the feedback loop of increasingly expensive Year Round charges would continue all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



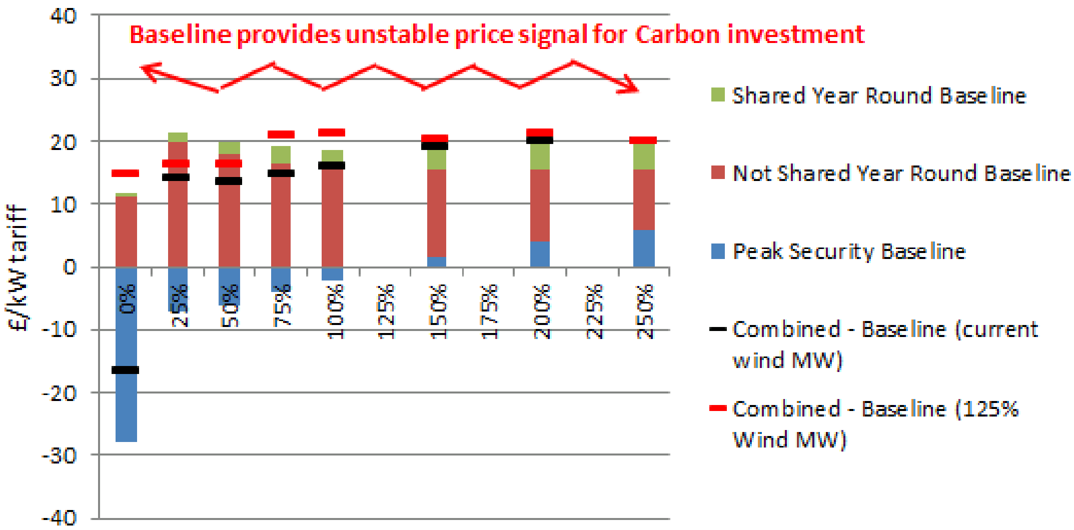
3.2. Baseline Peak Security tariff tends to provide opposite price signal to Baseline Year Round

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 prioivded 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

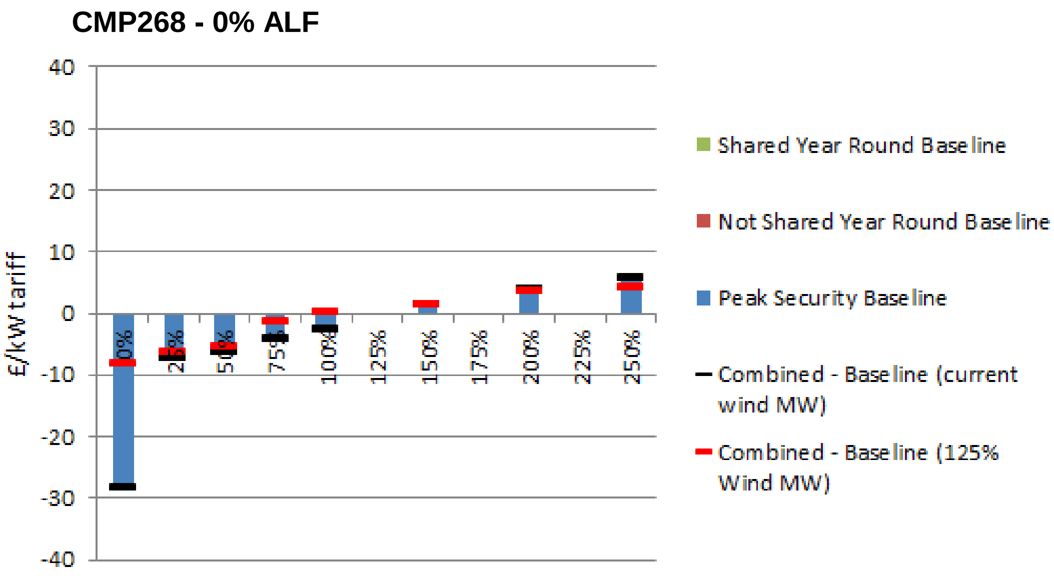
The same tariffs were applied using the proposed CMP268 tariff formula with the resulting charges for a Conventional Carbon generator as illustrated in the graphs below. This demonstrates the following beneficial characteristics of proposa, CMP268:

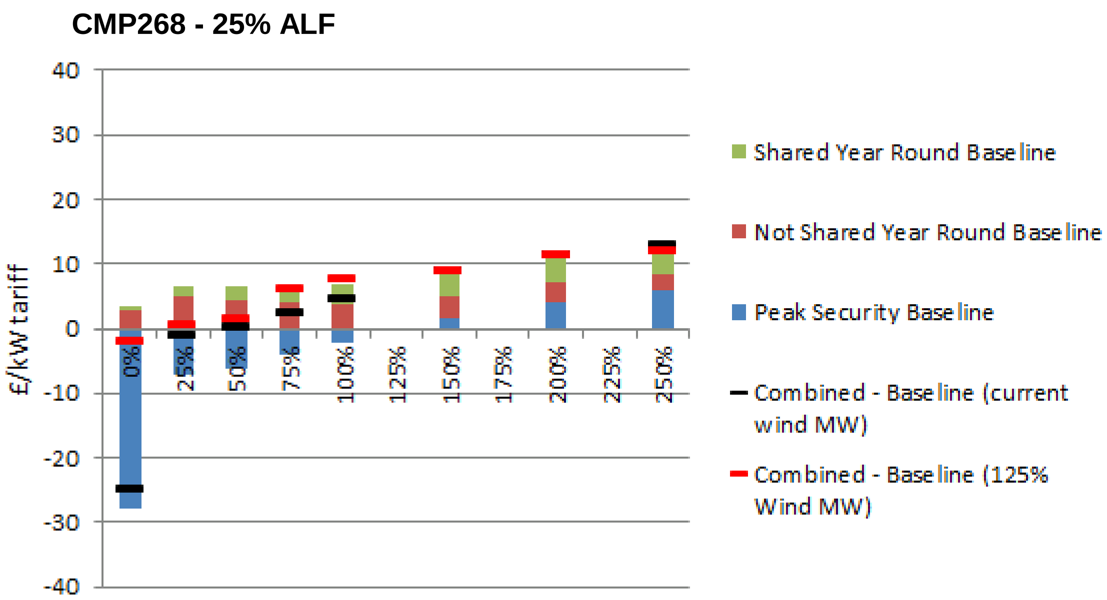
1. **Price signals tend towards equilibrium** – In contrast to the Baseline charging methodology, the set of price incentives provided by CMP268 do tend towards an economic equilibrium. This occurrs because the transmission price signal for Conventional Carbon generators in Scotland tends to become more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

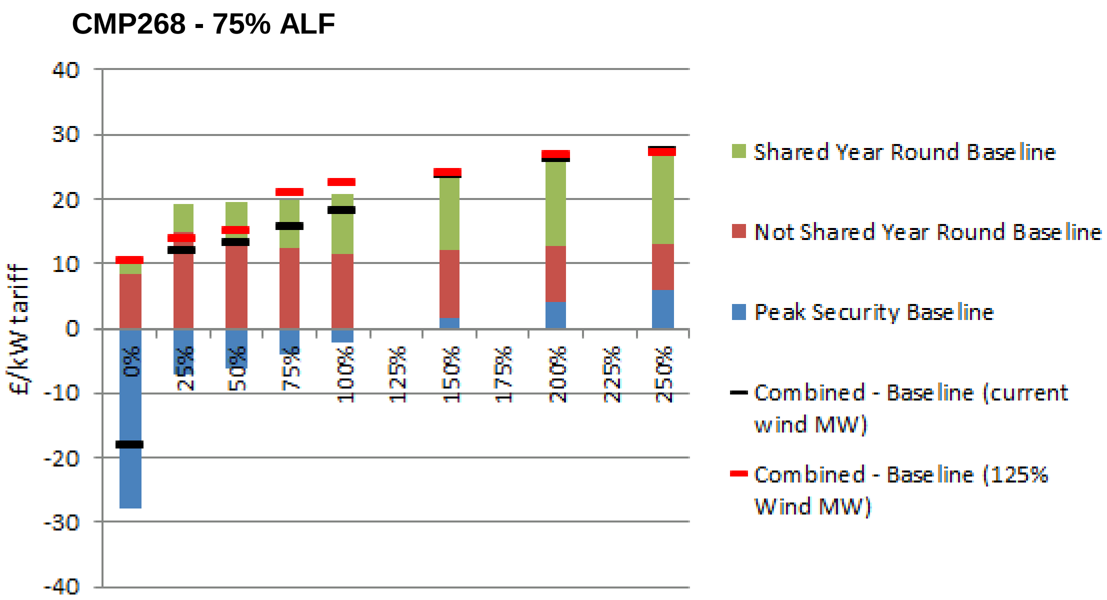
2. **More appropriately different charges for different generators** – Graphs below illustrate:
   a. **For a 0% ALF generator** - The price signal it receives is driven by the Peak Security tariff element, which is consistent witht the SQSS treatment of OCGTs. This illustrates that if there were to 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
40
30
20
10
0
-10
-20
-30
-40
£/kW tariff
0%
25%
50%
75%
100%
125%
150%
175%
200%
225%
250%
Shared Year Round Baseline
Not Shared Year Round Baseline
Peak Security Baseline
Combined - Baseline (current wind MW)
Combined - Baseline (125% Wind MW)


CMP268 - 25% ALF
40
30
20
10
0
-10
-20
-30
-40
£/kW tariff
0%
25%
50%
75%
100%
125%
150%
175%
200%
225%
250%
Shared Year Round Baseline
Not Shared Year Round Baseline
Peak Security Baseline
Combined - Baseline (current wind MW)
Combined - Baseline (125% Wind MW)


CMP268 - 75% ALF
40
30
20
10
0
-10
-20
-30
-40
£/kW tariff
0%
25%
50%
75%
100%
125%
150%
175%
200%
225%
250%
Shared Year Round Baseline
Not Shared Year Round Baseline
Peak Security Baseline
Combined - Baseline (current wind MW)
Combined - Baseline (125% Wind MW)

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)

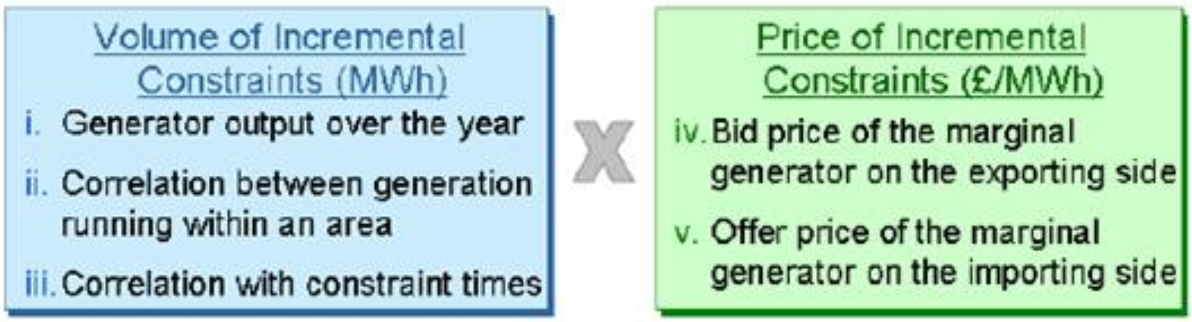


Figure 5 – Components that drive transmission constraint costs

"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]

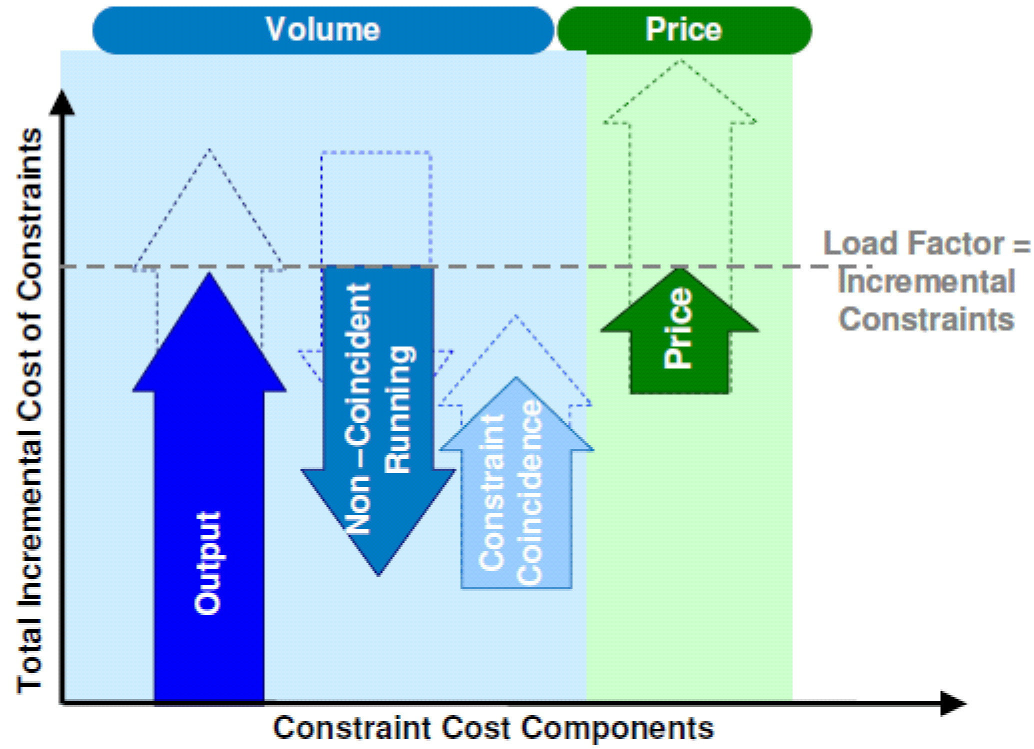


Figure 6 - Price and Volume constraint cost drivers

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)

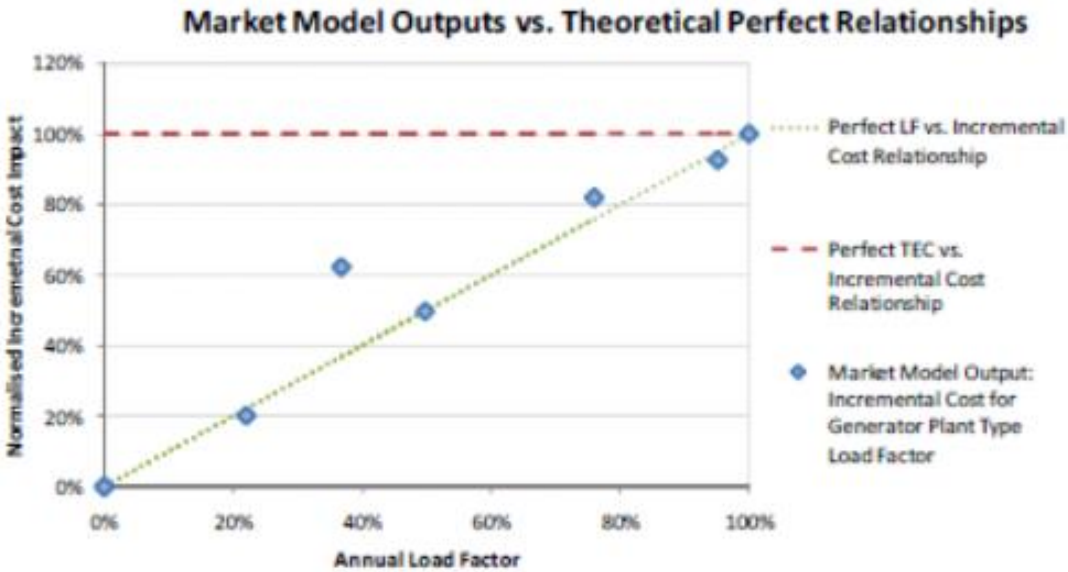


Figure 1 – Market Model Outputs vs. Theoretical Perfect Relationships

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)

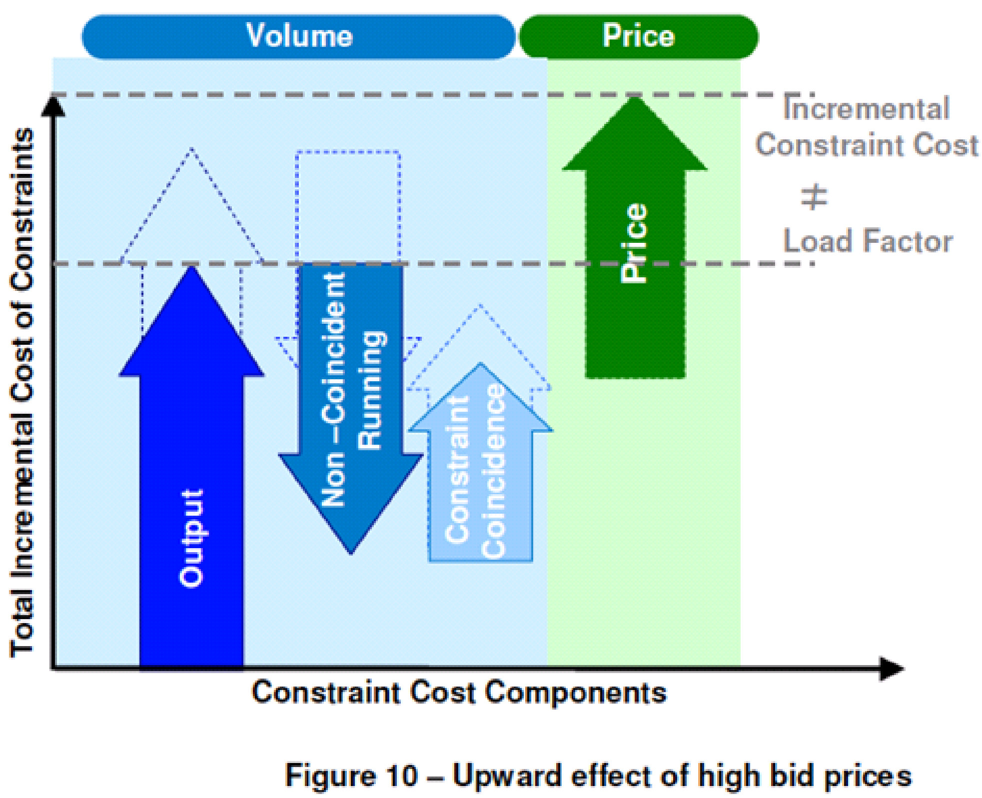


Figure 8: taken from Figure 5 of the CMP213 Workgroup Final Report.

"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]

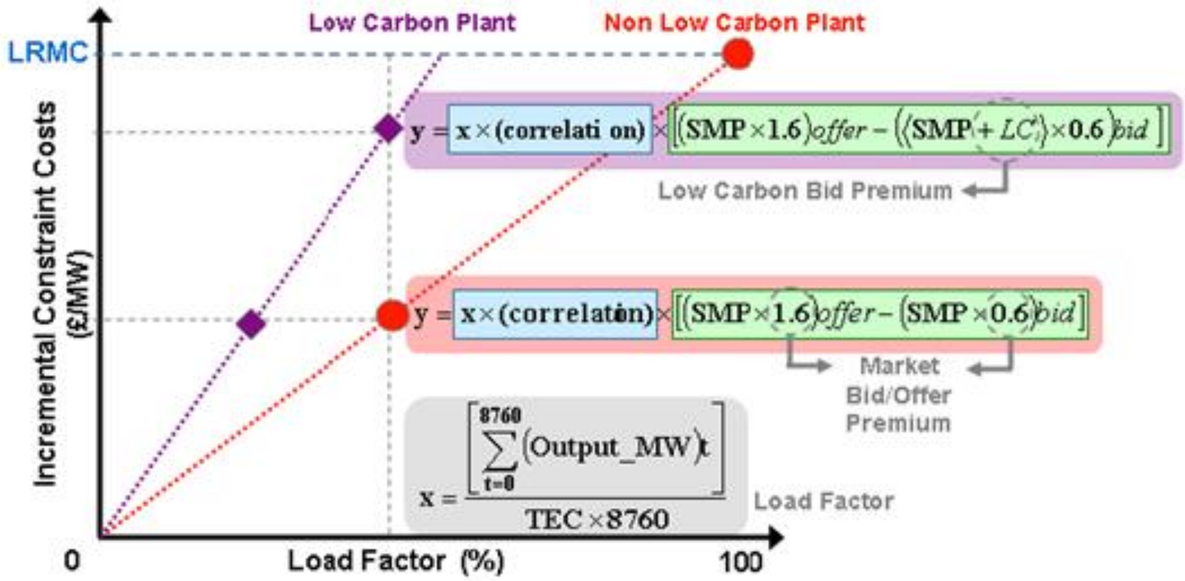


Figure 21 – Combined effect of price and load factor on constraint costs

"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]

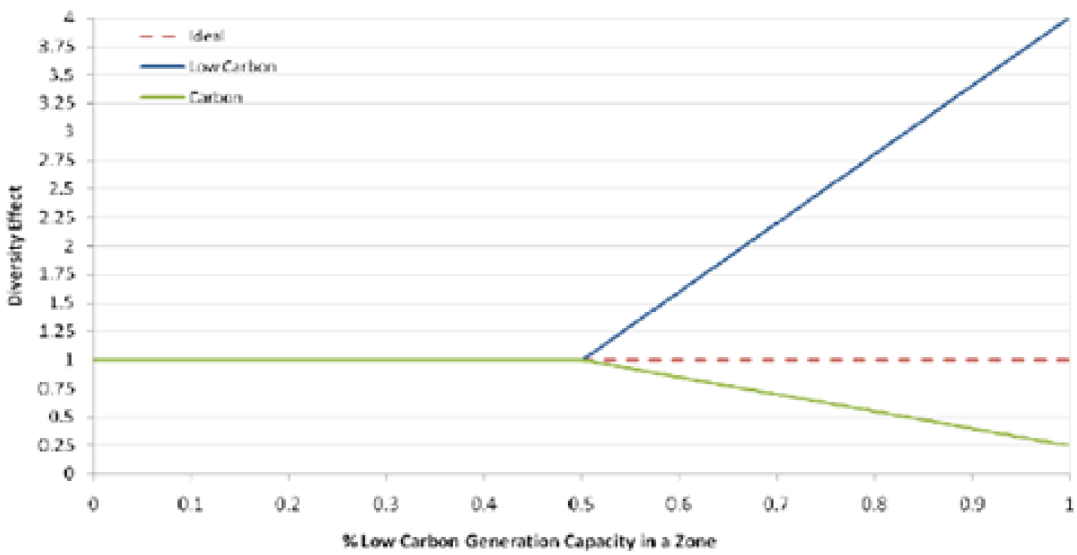


Figure 12 – Normalised effect of Load Factor with changing percentage generation mix in a zone

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.

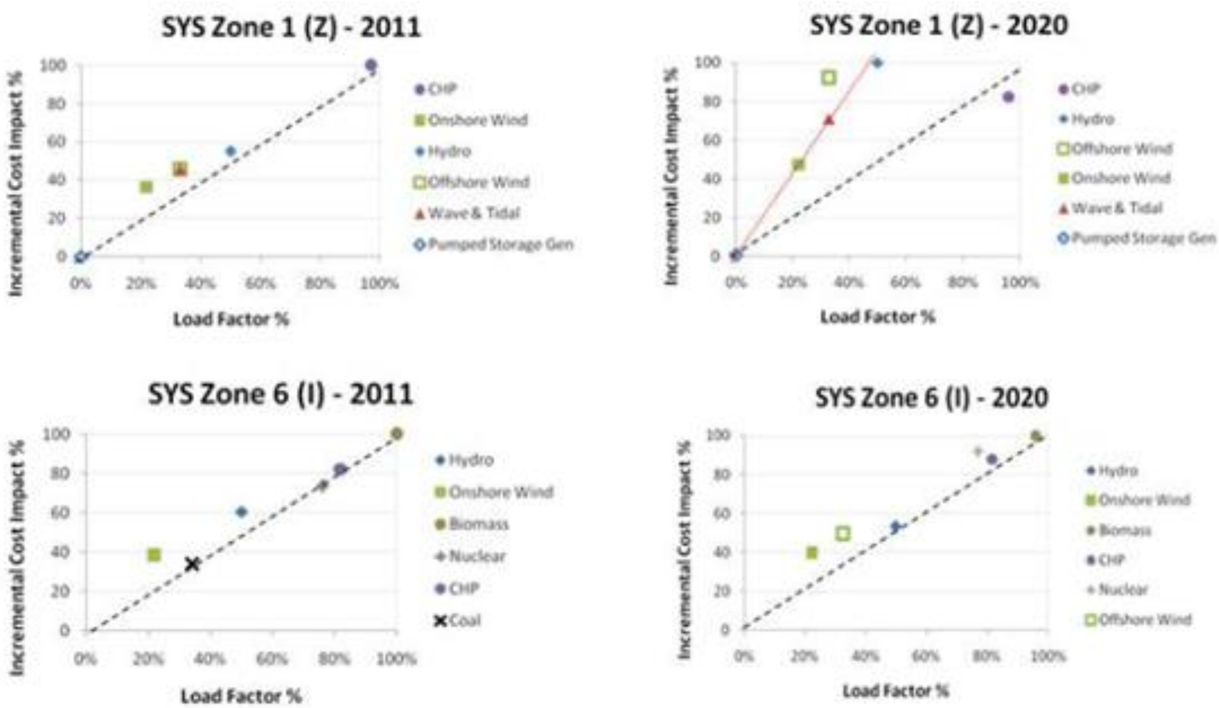


Figure 27 – Long term deterioration of the Load Factor vs. Incremental Constraint Cost relationship

“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)

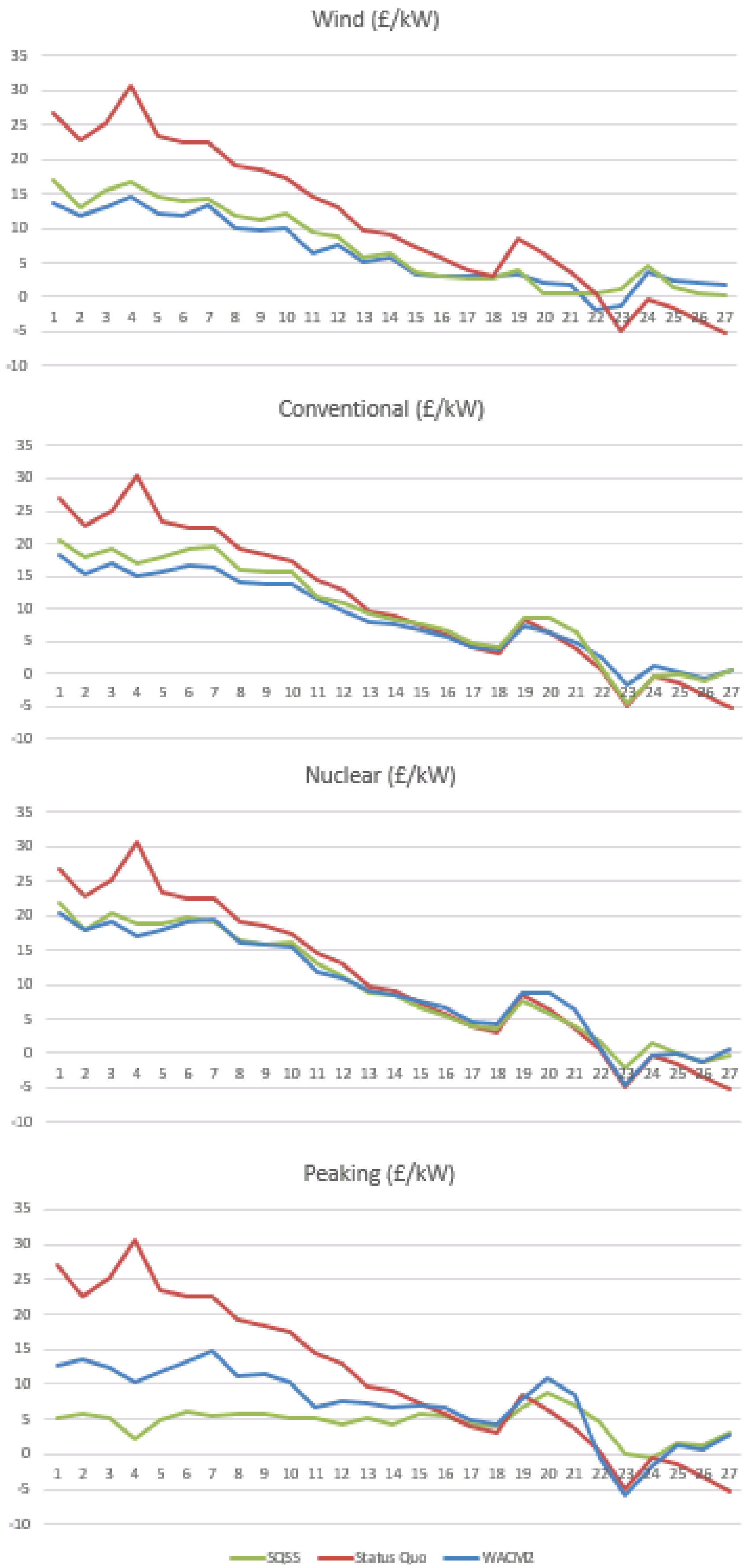
Plant Type	TEC	Generation - Peak Security	Generation - Year Round	Peak Security Generation	Generic LF Generation
Conventional	61,386	73%	66%	100%	75%
Intermittent	5,378	0%	70%	0%	25%
Peaking	5,455	73%	0%	100%	1%
Pumped Storage	2,744	73%	50%	100%	30%
Nuclear & CCS	10,841	73%	85%	100%	60%
Interconnectors	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)
SQSS
Status Quo
WACM2

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.”

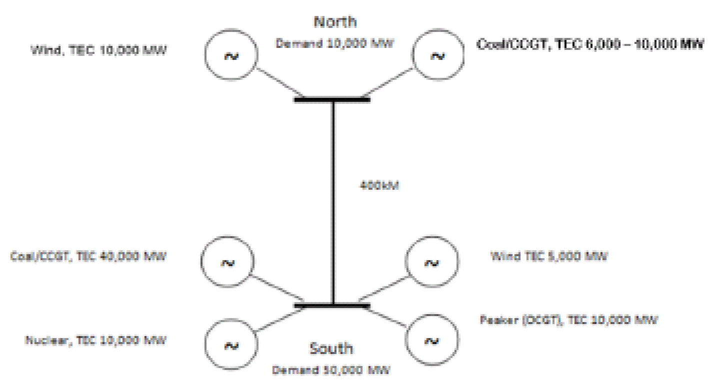


Figure 3, Simple 2 bus representation of GB system

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

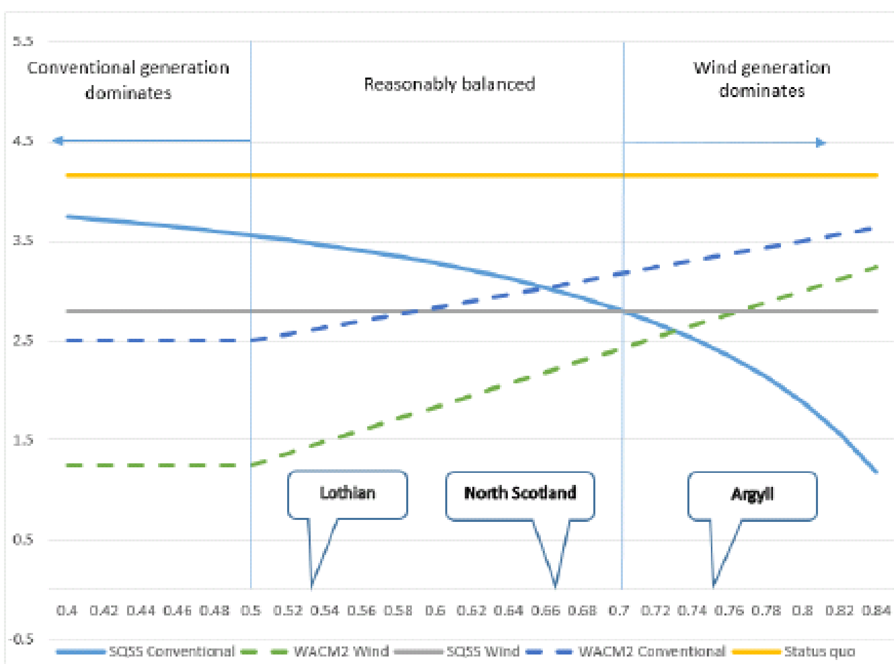


Figure 4. Variation of SQSS costs (£/kW) and WACM2 & Status Quo charges (£/kW) with sharing

"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

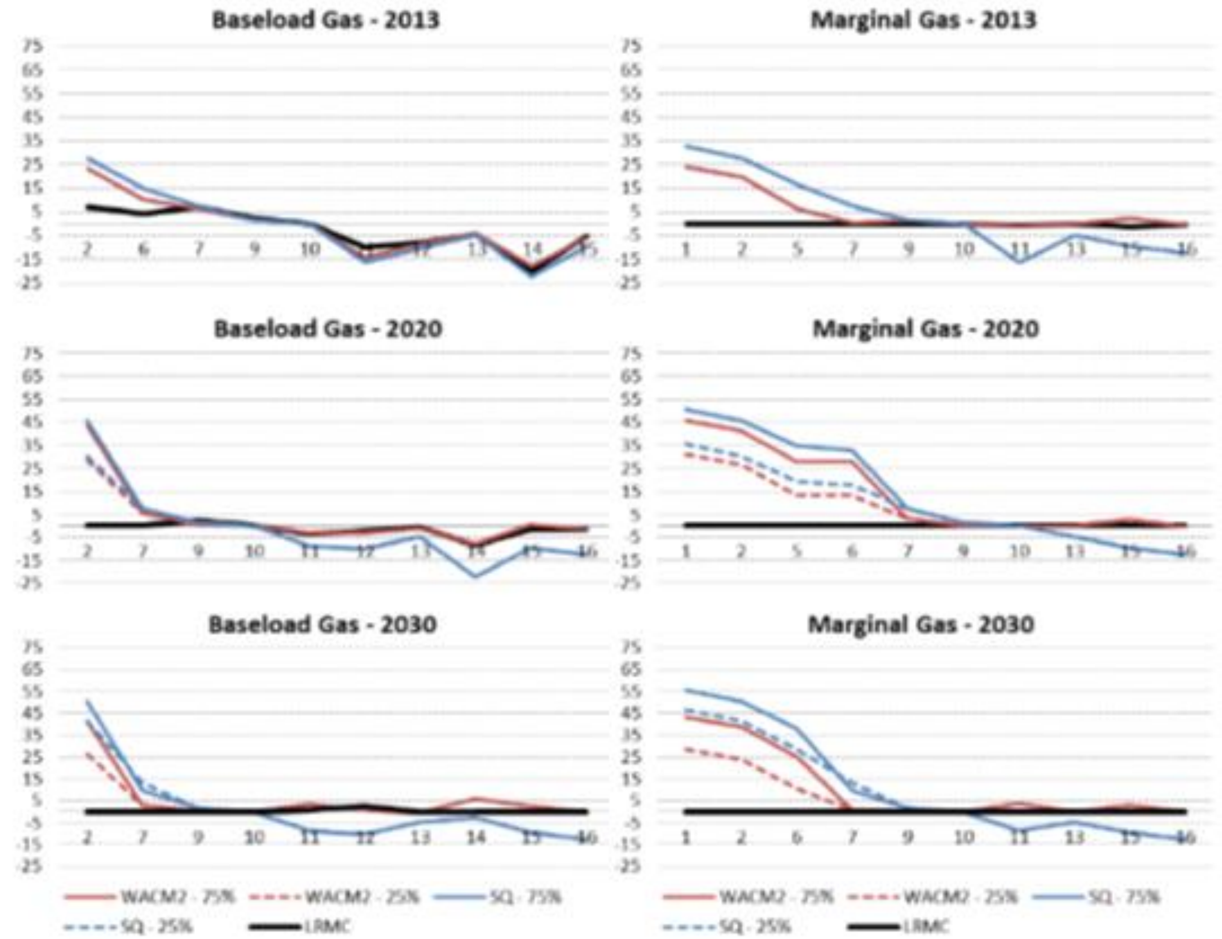
RWE procured analysis from NERA/ICL, Assessing the Cost Reflectivity of Alternative TNUoS Methodologies (February 2014)2 which compared the TNUoS tariffs derived from the pre April 2016 Status Quo charging methodology and those provided by the CMP213 WACM2 methodology with an analysis of Long Run Marginal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

> "**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**. WACM 2 tariffs for this type of generator tend to be lower in Scotland, and so are marginally closer to LRMC. In other words, **both status quo and WACM 2 exaggerate the locational signal conveyed through TNUoS as compared to LRMC.** 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]

> "**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**. 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

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

<table>
<tr><th>Q</th><th>Question</th><th>Response</th></tr>
<tr><td>1</td><td>Do you believe that CMP268 Original proposal, or any potential alternatives for change that you wish to suggest, better facilitates the Applicable CUSC Objectives?</td><td>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.

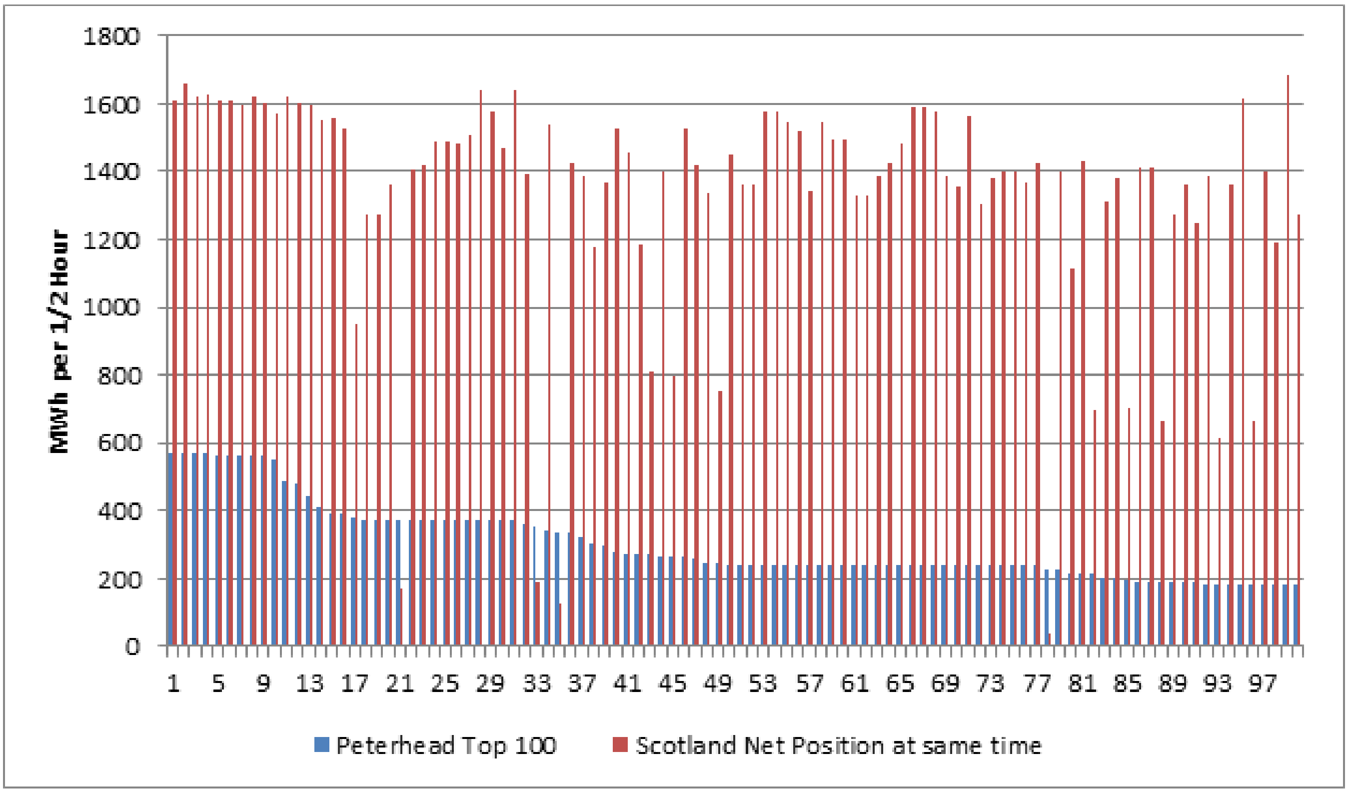
Process:
The timescale for consideration of the modification proposal, and the way it has overlapped with other significant charging changes which draw on much of the same pool of industry expertise, has prevented a thorough debate and it was not possible at the workgroup to debate or evaluate well the 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.</td></tr>
</table>

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'

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:	*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 Code Administrator 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 **03 November 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 included within the Draft CUSC Modification Report to the CUSC Panel and within the Final CUSC Modification Report to the Authority.

Respondent:	*James Anderson* *james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management Limited*
Please express your views regarding the Code Administrator 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.). (e) promoting efficiency in the implementation and administration of the CUSC arrangements. *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).*

Code Administrator Consultation questions

Q	Question	Response
1	**Do you believe that CMP268 better facilitates the Applicable CUSC objectives? Please include your reasoning.**	Without a detailed re-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 behind a transmission boundary, 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. Therefore the proposal does not better facilitate Applicable Charging Objective (ACO) (b). Cost reflective charges 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 ACO (a). The proposal is neutral against ACOs (c), (d) and (e) and overall will not better meet the ACOs than the current baseline.
2	**Do you support the proposed implementation approach? If not, please provide reasoning why.**	While we do not support implementation of CMP268 we would support the proposed implementation approach.
3	**Do you have any other comments?**	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 and that the issue would merit further examination and analysis that the workgroup was unable to pursue due to time constraints.

CUSC Code Administrator 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.

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

These responses will be included within the Draft CUSC Modification Report to the CUSC Panel and within the Final CUSC Modification Report to the Authority.

Respondent:	*Aled Moses (almos@dongenergy.co.uk, 020 7811 1055)*
Company Name:	*DONG Energy*
Please express your views regarding the Code Administrator 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.). (e) promoting efficiency in the implementation and administration of the CUSC arrangements. *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).*

Code Administrator Consultation questions

Q	Question	Response
1	**Do you believe that CMP268 better facilitates the Applicable CUSC objectives? Please include your reasoning.**	No, we believe that CMP268 does not better facilitate the Applicable CUSC objectives. In our view CMP268 is negative on objectives (a) and (b) and neutral on objectives (c), (d) and (e). In our view CMP268 does not provide a case that overall generators will face charges that are more cost reflective of their impact on the transmission network. Under CMP213 WACM2 the Year Round Not Shared tariff reflects the impact of generators, convention and non-conventional, not being able to “share” circuits where there are significant proportions of low carbon generation, and therefore their impact will be based on their capacity and not scaled. In our view CMP268 represents a fundamental change over how CMP213 was determined – namely that the Year Round Not Shared tariff represents transmission investment that can’t be shared. We do not think CMP268 has clearly addressed this fundamental point. As a result, CMP268 will likely result in generators facing less cost reflective tariffs and potentially create an uneven playing field. This will both worsen competition between generators, and result in charges that less accurately reflect their impact on the transmission network.
2	**Do you support the proposed implementation approach? If not, please provide reasoning why.**	No, we do not support the proposed implementation date. In our view the proposed implementation date undermines the predictability and certainty that is supposed to underpin the GB charging regime. Fundamentally, we can’t see any real benefit from this modification being implemented next year, while there are significant drawbacks.

Q	Question	Response
3	**Do you have any other comments?**	We are concerned that a modification with as significant and fundamental impact as CMP268 was raised as an urgent modification. The risks of having mods like CMP268 raised in this manner are that there is insufficient time to both perform sufficient, robust, scrutinised analysis, and engage effectively with stakeholders and industry. This significantly increases the risks of unintended consequences and modifications that do not actually meet the CUSC objectives or Ofgem's statutory duties. Modifications raised in this manner create risk and uncertainty that has to be carried by the users of the network, in this case, generators. This is particularly clear in this case – CMP268 could have been raised earlier; CMP213 has been in effect since this April, and Ofgem made their decision back in June 2014. In addition, while we appreciate the effort and considerable work that has gone into CMP268, the timescales that the workgroup has operated under have resulted in a report that is extremely difficult to understand. Our view is that any stakeholder that is not familiar with either TransmiT/CMP213 or the transport model will find it very difficult to understand and appreciate what CMP268 does.

CUSC Code Administrator 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 **03 November 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 included within the Draft CUSC Modification Report to the CUSC Panel and within the Final CUSC Modification Report to the Authority.

Respondent:	*Joe Underwood*
Company Name:	*Drax*
Please express your views regarding the Code Administrator 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.). (e) promoting efficiency in the implementation and administration of the CUSC arrangements. *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).*

Code Administrator Consultation questions

Q	Question	Response

1	**Do you believe that CMP268 better facilitates the Applicable CUSC objectives? Please include your reasoning.**	No. As detailed in our workgroup consultation response, the workgroup has had insufficient time to properly assess the proposal due to the short timescale. 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. 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 evolved and flows on the system are now proving problematic for the SO to manage. We do have some sympathy with the defect raised by the Proposer. In particular, the concept of sharing and the way that it is incorporated into the TNUoS charging method appears to be something which could be improved. 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, and specifically the current method of recognising network sharing, may not provide efficient signals for siting flexible plant in the North, particularly Scotland. A change to the charging arrangements should be considered to rectify this potential defect, however, CMP268 does not provide an adequate solution. 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 working 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
		The additional analysis provided by the proposer after the workgroup consultation regarding the SQSS sharing factors is incomplete. There has been no justification as to why this link has been made and therefore referencing the SQSS in this manner seems arbitrary and irrelevant. 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? If not, please provide reasoning why.**	No. The timescale for this change is too short. The implementation period should be at least one full charging year for a change of this nature, i.e. to ensure efficient cost pass-through in the traded market.
3	**Do you have any other comments?**	Not at this time.

CUSC Code Administrator Consultation Response Proforma

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

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Please send your responses by **03 November 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.

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These responses will be included within the Draft CUSC Modification Report to the CUSC Panel and within the Final CUSC Modification Report to the Authority.

Respondent:	Paul Mott
Company Name:	EDF Energy
Please express your views regarding the Code Administrator 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.). (e) promoting efficiency in the implementation and administration of the CUSC arrangements. *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).*

Code Administrator Consultation questions

Q	Question	Response
1	**Do you believe that CMP268 better facilitates the Applicable CUSC objectives? Please include your reasoning.**	No. We do not believe the proposal takes forward cost-reflectivity, 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, for which very good topical engineering reasons can be hypothecated, as shown empirically in citations from our evidence in the current workgroup report and in our last response. There has been too little time available for an evidence-based decision to be made on what amounts to 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, and the full judicial review that found no fault in the decision to pass CMP213. 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 ‘defect’ asserted by the proposer was considered in the far more thorough CMP213 process, and a balanced decision was made to adopt the current diversity method. Re-opening a single issue – the application of the CMP213 tariffs but not their calculation within the overall framework of the diversity method is unjustified.

Q	Question	Response
1 cont'd	**1 cont'd**	*Continuation to reply to question 1 (or text becomes invisible and unprintable)* 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 capacity there increases above 50%. Ofgem's decision letter said of 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."*
2	**Do you support the proposed implementation approach? If not, please provide reasoning why.**	No. 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

CUSC Code Administrator Consultation Response Proforma

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Please send your responses by **03 November 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 included within the Draft CUSC Modification Report to the CUSC Panel and within the Final CUSC Modification Report to the Authority.

Respondent:	John Tindal 01738 457308 John.tindal@sse.com
Company Name:	SSE
Please express your views regarding the Code Administrator 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.). (e) promoting efficiency in the implementation and administration of the CUSC arrangements. *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).*

Code Administrator Consultation questions

Q1 Do you believe that CMP268 better facilitates the Applicable CUSC objectives? Please include your reasoning.

Yes, as per our Workgroup consultation response, we believe that CMP268 Original better meets all of the applicable CUSC objectives. In particular, with regard to Objective (b), it better reflects the costs incurred by transmission licensees in their transmission businesses and with regard to Objective (a), it also better facilitates effective competition.

We believe that CMP268 addresses a defect in the CUSC baseline which understates the potential for capacity sharing by conventional plant in areas with high penetration of low carbon plant. In doing so it (the defect) overstates the cost associated with conventional plant in such areas and imposes a non-cost reflective charge on such plant which in turn undermines facilitation of effective competition.

Our rationale is outlined in detail further in the document covering:

1. The strong link CMP268 has with the Security and Quality of Supply Standards investment criteria (page 3);
2. The existing evidence base produced by Project TransmiT and CMP213 which is supportive of CMP268 (page 3-4);
3. The recognition of the defect outlined by CMP268 within the Project TransmiT and CMP213 process (page 4-5); and
4. Better meets CUSC objective “b” - How the key principles of capacity sharing lead to the improved cost reflectivity that would be delivered by implementation of the change proposed by CMP268 (page 5-6), including:

    4.1. Evidence regarding first key principle of sharing – Correlation with periods of constraint (page 6-7);

4.2. Evidence regarding the second key principle of sharing – Cost of being bid off (page 7-8); and additional analysis confirming that the principles applied during CMP213 continue to apply to CMP268 (page 8-9); and
4.3. Economic modelling carried out during CMP213 showing how key principles of sharing and diversity interact in practice (page 9-13).
5. Better meets CUSC objective “a”
6. Better meets CUSC objective “c”
7. Better meets CUSC objective “d”
8. Better meets CUSC objective “e”

In addition, we suggest that the counter- statements made by other Workgroup members in the Workgroup consultation are not based on any valid economic rationale and we provide our response (page 14-23) to the specific issues raised in these statements.

Given the extensive analysis and evidence supporting the change proposed by CMP268 and the fact that CMP268 clearly follows the principles which the TNUoS charging methodology is based on, we do not see any good reason as to why CMP268 implementation should be delayed beyond April 2017.

1. CMP268 has a strong link with the SQSS investment criteria and CBA approaches

The Security and Quality of Supply Standards (SQSS) has two criteria for determining the need for transmission investment; (i) the Demand Security Criteria and (ii) the Economy Criteria; which use scaling factors to adjust plant capacity to determine transmission investment need. The CMP268 defect relates specifically to the Economy Criteria of the SQSS. The purpose of the SQSS Economy criteria is to indicate where transmission network reinforcement may be justifiable as an economically efficient approach to managing constraint cost. However, before an investment decision is made to reinforce the transmission network, a full detailed Cost Benefit Analysis (CBA) is carried out. The result of this CBA analysis may be to support the economic case for investment in order to avoid constraints (possibly greater investment than that indicated by the SQSS Economy Criteria), or it may be to conclude that transmission network investment may not be economically justified in which case a derogation from the SQSS Economy Criteria would be required and the identified transmission network reinforcement investment would not take place.

The purpose of the simplified scaling factors of the SQSS is to be reflective of a full detailed CBA (which is reviewed from time to time to ensure that the SQSS remains broadly cost reflective), although it is clear (given the complexity etc., involved) that the SQSS scaling factors represent a form of average and cannot therefore be as fully cost reflective as an individual CBA for every eventuality of power station type and transmission network investment that they give rise too. Because it is ultimately a full detailed CBA which drives the actual transmission network investment cost incurred by the TO, then while it is appropriate that the Transmission Network Use of System (TNUoS) charging methodology should be broadly cost reflective of the SQSS Economy Criteria scaling factors, it remains appropriate that the charging methodology; set out in Section 14 of the CUSC; may differ from this if this enables the charging methodology to be more cost reflective of a full detailed

CBA. This principle underlined the introduction, as part of the CMP213 approved changes, of the Average Load Factor (ALF) to the charging methodology (as a proxy for a detailed CBA) and also underpins the proposal within CMP268 to apply the ALF to the entire Year Round tariff for Conventional Carbon generators (which we consider is a further improvement to this CBA proxy).

2. Project TransmiT and CMP213 evidence base is already sufficient to support CMP268

CMP268 is a natural and relatively simple extension which builds on the principles of sharing and diversity which have already been developed, evidenced and introduced into the TNUoS charging methodology within the CUSC through the approved CMP213 changes.

The evidence for the better cost reflectivity of the CMP268 Original has already been clearly presented, and expert peer reviewed, over a period of around four years during the comprehensive Project Transmit (and then CMP213) process including substantial in depth expert analysis. During the CMP268 Workgroup process, we presented a summary and interpretation of this previous analysis and some additional new analysis to further illustrate the better cost reflectivity of CMP268.

This CMP268 proposal does not require a re-opening of the extensive analysis which was already carried out during Project Transmit and CMP213 - instead it simply requires an incremental additional application of that previous analysis, which has already been carried out. It is our view that there is already sufficient existing detailed analysis which supports the better cost reflectivity of CMP268 and that further new analysis or evidence is not be required.

3. The defect described by CMP268 was already well understood and recognised in Project TransmiT and CMP213

As Project Transmit and CMP213 demonstrate, the changes to the TNUoS charging methodology introduced by CMP213 are much better than the pre-CMP213 baseline. However, the methodology introduced by CMP213 does include some opportunities for further, incremental, improvement.

The CMP213 Workgroup report acknowledged at the time that the defect (identified by CMP268) remained present in the CMP213 WACM2 solution. As with previous substantial CUSC changes, such as those introduced by CMP213, it is a standard approach of the CUSC process to implement changes on an incremental basis where these opportunities for improvement arise.

The CMP268 Code Administrator Consultation states that “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.” [1] The full quote from the CMP213 Code Administrator Consultation report is shown below:

[1] CMP268 Code admin consultation with annex, 4.7 http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP268/

"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 ***<u>the carbon generator's TNUoS charge will be based predominately on capacity, even though the carbon generator is sharing 100% with low carbon generation</u>***." (4.70) [emphasis added]

The CMP268 Code Administrator Report (Section page 167) also includes a quote from Poyry in a report to Centrica, submitted during the CMP213 process, which supports this position with further explanation:

"Under Diversity 1, there would be almost no sharing assumed…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 ***<u>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</u>****."* (Poyry 3.2.1.4)[2] [emphasis added]

4. Better meets CUSC objective "b" - The better cost reflectivity of CMP268 follows from the key principles of sharing

CMP268 is consistent with the principles of sharing described in the National Grid Original modification proposal (CMP213) and also as described in the CMP213 Code Administrator Consultation. We have already described and explained these principles in detail - as set out in the CMP268 Code Admin consultation (sections 3.1 to 3.3 and also pages 153).

The two key principles of sharing i.e. regarding the degree to which generators may cause constraint cost are:

(1) Correlation with periods of constraint and

(2) Cost of being bid off to manage constraints.

These two principles apply to conventional carbon generators such that in practice, they continue to share even if they are behind a transmission network boundary dominated by low carbon generation which can be explained simply by the following statement:

Conventional carbon generators will tend to avoid generating during periods when constraints are most likely and even if they are generating, during those periods, then they will tend to be relatively low cost for the System Operator to bid off, so provide a relatively low cost option for mitigating those constraints.

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

These principles were widely accepted during the long and detailed process of CMP213, and they will be well understood by someone with an understanding of the economic principles of merit order dispatch and experience of how the wholesale market operates in practice.

It should not be necessary to revisit these principles, however for the sake of completeness, we did provide new analysis to the CMP268 Workgroup to explicitly demonstrate that these accepted principles behind CMP213 and CMP268 do continue to apply in practice[3].

These principles were described and discussed within the CMP268 Workgroup from the very first Workgroup meeting. During the Workgroup process, other Workgroup members stated their opinion that these key principles do not apply, however they failed to provide any valid economic rational, or any valid evidence to support their opposing opinion, so these were merely supposition and assertion which should not be given undue weight when considering the merits of CMP268.

The only economic rationale which did attempt to provide a counter view was discussed in sections 4.13 to 4.22 of the CMP268 Code Administrator Consultation and also in the Workgroup consultation response submitted by EdF which discussed whether Conventional Carbon plant may be constrained on for system stability reasons.

However, this counter view was clearly demonstrated to be not valid in the following ways:

1. **Not valid in principle** – The CMP268 Workgroup report section 4.16.1 explained the reasoning why *"..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*." [emphasis added]. John Tindal's (SSE) voting Workgroup rational including a quote from the SQSS to further clarify this:

   > *"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****."* (CUSC Section 14, paragraph 14.14.6) [emphasis added]

2. **Not valid in practice** – The additional analysis provided in the SSE Workgroup consultation response[4] demonstrated that, in practice, the historic dispatch profile of Conventional Carbon generators has been consistent with the CMP268 proposal and not consistent with the thesis suggested by EdF.

3. **No valid evidence provided to the contrary** – The CMP268 Workgroup discussion explains that the source data used by EdF in their analysis was distorted by other factors[5] , so does not in fact support the conclusion which EdF attempted to derive from it. In particular, EdF attempted to make a generalised conclusion by relying on highly selective data taken from a (short) period of two to three weeks (out of 52 weeks in the year) of generation by Peterhead during which time the station was subject to the SBR contractual obligations which restricted its operation to specifically

[3] New analysis – Evidence supporting CMP268, CMP268 Code Administration Consultation p139.

[4] CMP268 Code Administrator Consultation pages 143 to 147

[5] CMP268 Code Administrator Consultation 4.16 to 4.22 and 4.81

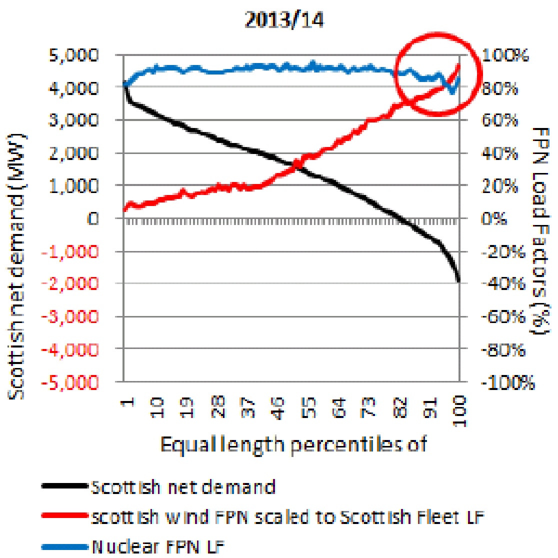
avoid high levels of generation during peak hours. This very limited data set is therefore not at all representative of the normal commercial operational profile of a thermal power station over the course of a year, so EdF's generalised assertions and conclusions cannot be supported by this limited data set.

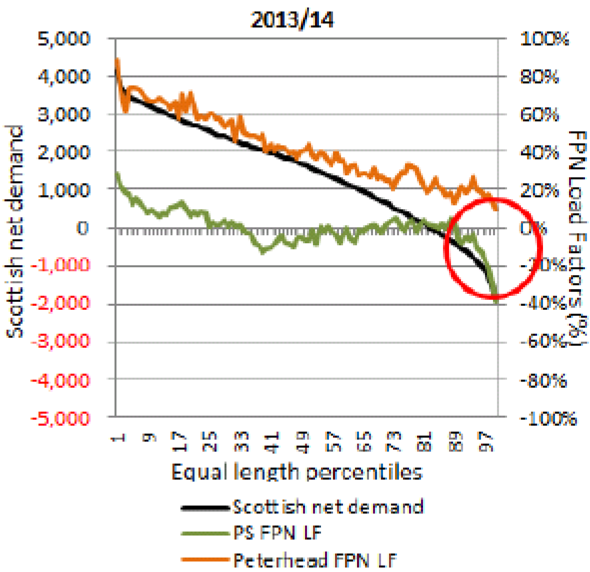
4.1. Evidence regarding first key principle of sharing – Correlation with periods of constraint

The two graphs below are an extract of this evidence which SSE provided to the CMP268 workgroup. These graphs demonstrate that the empirical data is consistent with the stated principles namely that the sharing characteristics of Conventional Carbon generation are very different from that of Low Carbon generators with regard to the cost of investment which they cause when they are located behind a transmission network boundary dominated by low carbon generation. Because in this specific scenario, these two types of generation cause transmission network investment costs which are very different from each other, it is therefore not appropriate that the CUSC baseline charging methodology treats them as if they were the same as each other This clear difference in practice is consistent with the conclusions described above.

The first graph shows that Low Carbon generation tends to exhibit relatively ***high*** load factors during periods when constraints are most likely, while Conventional Carbon generators tend to exhibit relatively ***low*** load factors during periods when constraints are most likely.

Because this empirical data further confirms that the first key principle of sharing does in fact tend to apply in practice as it would, according to economic theory, be expected to, then it appears very difficult to reasonably question this first key principle underlying CMP213 and CMP268 either in principle, or in practice.





4.2. Evidence regarding the second key principle of sharing – Cost of being bid off

The second key principle behind the approach of sharing is that even if Conventional Carbon generators plan to generate during periods when constraints occur, they can be constrained off at a relatively ***low cost***. This characteristic contrasts with Low Carbon generators which tend to exhibit relatively ***expensive*** bid prices. As we have previously explained it is the presence of Low Carbon generator which causes sharing to break down because they tend to exhibit relatively high load factors during periods of constraint and exhibit relatively expensive bid prices, so if they do not have Carbon plant to share with, then they tend to cause a relatively high cost of constraint closer to their capacity and this is what the CMP213 Diversity 1 approach reflects; and is demonstrated in 'Figure 17' below. By contrast, Conventional Carbon generators continue to share fully even if a transmission network boundary is dominated by low carbon generation because their characteristic of inverse correlation with periods of constraints and their relatively low cost bid prices continue to drive a relatively low cost of constraints, therefore a relatively low cost of network investment.

The graph below was taken from the CMP213 Final Report[6] and was used by the CMP213 Workgroup at the time as part of the classification of generators into the two classes, namely 'Low Carbon' which tends to exhibit relatively expensive bid prices and 'Carbon' which tends to exhibit relatively low cost bid prices.

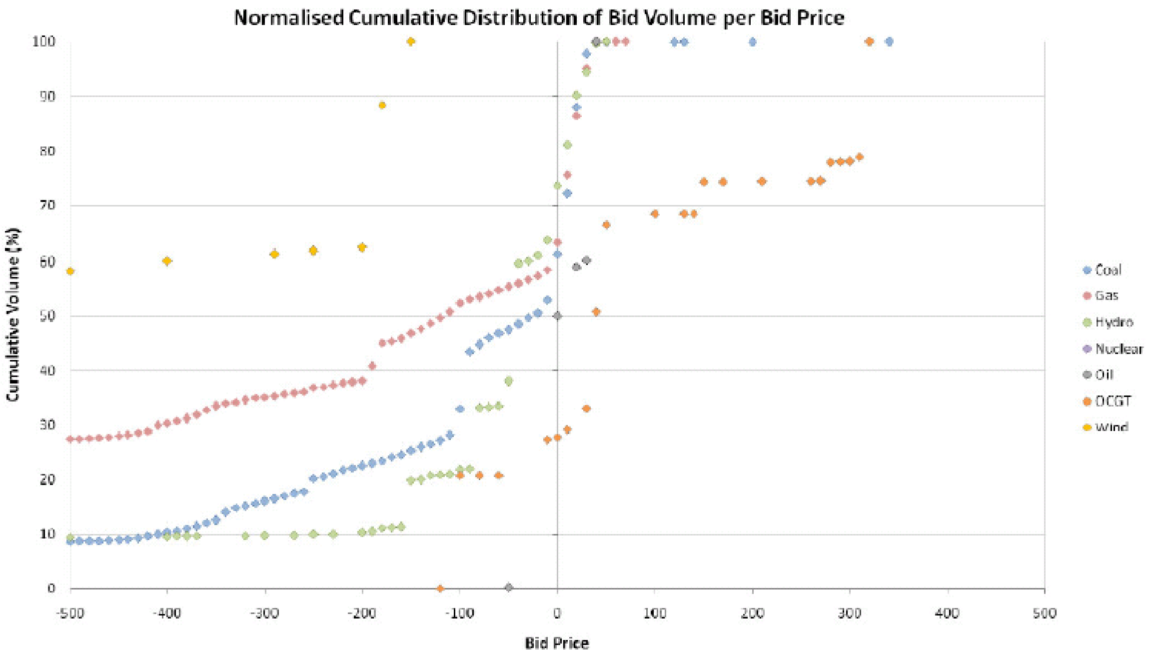


Figure 17 – Normalised Cumulative Distribution of Bid Volume per Bid Price

In their CMP268 Workgroup consultation response, EdF noted that this bid price analysis had not been updated as part of the CMP268. It is our view that CMP268 does not require a fresh analysis of the latest bid price data in this regard because CMP268 simply uses the same existing interpretation of the data as is currently used within the CUSC baseline methodology and the wider interpretation of this data is not being questioned.

Notwithstanding that, for the avoidance of doubt, we have carried out new analysis to refresh this bid price analysis work, as described below.

<u>New analysis not presented to the CMP268 Workgroup confirms that the principles applied during CMP213 continue to apply to CMP268</u>

The graph below represents new analysis which we have not previously provided to the CMP268 Workgroup. This analysis refreshed the CMP213 analysis and confirms that the principles which applied during CMP213 continue to apply now. This new analysis is consistent with what should be expected and the results should not be surprising to someone who is familiar with how the GB electricity wholesale market operates. This used

[6] Final CUSC Modification Report Volume 1, Figure 17
file:///C:/Users/JT78680/Downloads/Final%20CUSC%20Modification%20Report%20Volume%201%20(2).pdf

the bid price and volume pairs of bids which were taken using all available GB BMUs for some of the major generating technologies.

There are three key points which can be taken from this analysis:

1. Wind exhibits relatively expensive bid prices, so is relatively expensive to constrain off;

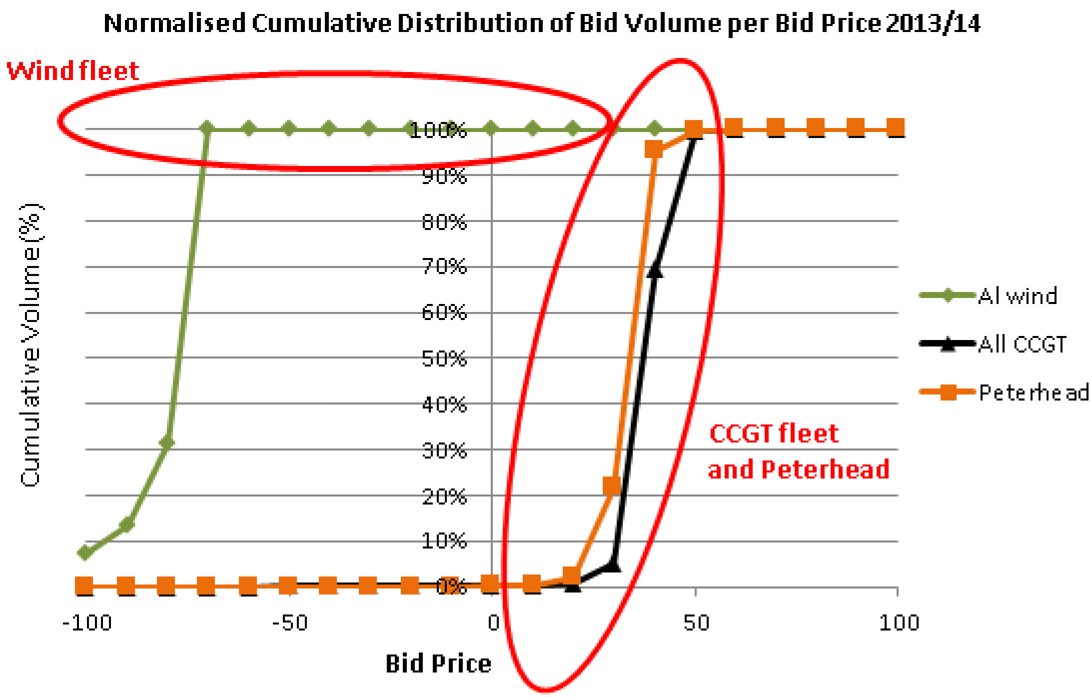
2. On average, CCGTs exhibit positive bid prices close to the marginal cost of turning on a different generator, so are relatively low cost to bid off; and

3. Peterhead has exhibited bid price patterns which are very close to the average CCGT fleet.

This empirical data further confirms that, as with the first key principle, the second key principle of sharing applies in practice. This is as would be expected to according to economic theory. Therefore this second key principle underlying CMP213 and CMP268 is robust to challenge both in principle and in practice.

Acceptance of this second key principle, taken together with the first key principle should be all that is required to demonstrate the economic rationale regarding why the small change introduced by CMP268 is more cost reflective than the CUSC baseline.

It was striking that during the CMP268 Workgroup discussion and Workgroup consultation responses, no valid economic rationale or evidence was provided to counter the economic theory, or the empirical result of either of these two key principles.



4.3. Economic modelling carried out during CMP213 provides sufficient evidence how key principles of sharing and diversity interact in practice

As described above, the economic principles behind transmission network sharing should be sufficient to allow appreciation of why the small change introduced by CMP268 is more cost reflective than the CUSC baseline. However, these same principles also applied during the CMP213 Workgroup process and further work was carried out during that time to explore in greater detail how these two key principles may be expected to interact in practice.

At the start of the CMP268 Workgroup process (before the second Workgroup meeting) we presented a summary of some of this detailed economic modelling which was previously carried out and peer reviewed by the CMP213 Workgroup. This pre-existing economic analysis supports the case of CMP268 that Conventional Carbon generators do continue to fully share even if they are behind a transmission network boundary dominated by low carbon generation and it is therefore more cost reflective to recognise this in the transmission charging arrangements. This economic modelling builds on the principles described above to provide more quantitative analysis. This analysis was summarised in the CMP268 Code Administration Consultation (paragraphs 3.1 to 3.31) and further detail of quotes taken from the original analysis can be found in its appendix (pages 152 to 167).

This evidence, described below, was based on economic principles rather than empirical observation. Therefore the analysis and conclusions which were considered appropriate for CMP213 remains appropriate and valid for the purposes of CMP268. The underlying fundamental economic principles which the analysis and conclusions supported have not changed in the intervening period since CMP213 was approved.

The bulk of the members of the CMP268 Workgroup were involved throughout the CMP213 process, so the evidence presented during the CMP268 Workgroup was not new to them. They had previously discussed and considered it, in great detail, as part of the previous lengthy and comprehensive CMP213 Workgroup process. Other members of the CMP268 Workgroup appear to have either ignored this previous evidence, or dismissed its conclusions. However, they did not provide any valid economic justification for doing so.

The bullet points below summarise the key conclusions from that previous comprehensive CMP213 analysis.

1. **Circumstances where sharing is reduced** - The CMP213 Final Modification Report Volume 2, Annexes included a theoretical model illustrating the impact of diversity on the cost of constraints. This model illustrated that in circumstances with a relatively low level of diversity, then the cost of constraints, therefore cost of transmission network reinforcement caused by Low Carbon Plant would increase, however the cost of constraints and transmission network investment caused by Conventional Carbon Plant would remain the same as it was when there was sufficient diversity. The paragraph explained this as: "*for areas of the transmission system with insufficient generation plant diversity…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.*"[7]

[7] CMP268 Code Administration Report page 158. Original source: CMP213 Final CUSC Modification Report Volume 2, Annexes, 4.118

2. **Evidence – Simplified two node model** - The CMP213 Final CUSC Modification included a summary of a two node model with the following explanation: "*It follows in these circumstances that incremental low carbon plant increases constraint costs whilst incremental carbon plant reduces incremental constraint costs.*"[8] [emphasis added]. This analysis illustrated that as the % of Low Carbon Capacity in a Zone increased, then the constraint cost caused by an incremental MW of Carbon plant reduced below that indicated by its load factor. This suggest that behind transmission network boundaries dominated by low carbon generation, it may be more cost reflective to charge Carbon generators a discount to their ALF; i.e. make TNUoS charges become cheaper for Carbon plant, which is the opposite of what the CUSC baseline currently does.

3. **Evidence – ELSI Market Model** – As part of the CMP213 process, National Grid carried out analysis using their ELSI Market Model and some results of this were included in the CMP213 Workgroup Report.[9] This analysis illustrated that in Figure 27, in the SYS Zone 1 (Z) 2020 scenario, the higher proportion of low carbon generation in 2020 causes a breakdown in sharing for low carbon plant, however for Carbon plant (in this example CHP and pumped hydro), the sharing benefit does not break down and their incremental cost impact of remains on the idealised curve proportional to load factor as it was before. This evidentially based result is consistent with the approach proposed by CMP268.

4. **Evidence Cost reflectivity compared with SQSS – During the CMP213 process, P E Baker carried out analysis for SSE to show** *"..the charges for each generation technology and how these compare with the costs implied by the SQSS*."[10] This analysis demonstrated that the TNUoS charges following from CMP213 were substantially more cost reflective that the pre-CMP213 baseline, however that even after this improvement in cost reflectivity, the new solution still appeared to be substantially over charging low load factor peaking plant which are located behind transmission network boundaries dominated by low carbon generation. This analysis supports the introduction of CMP268 in the way that it would further improve the cost reflectivity of TNUS charges with regard to those specific peaking plant (classed as Conventional Carbon), while leaving the locational charges faced by peaking plant in other locations and other types of generating plant either entirely, or largely unchanged.

5. **Evidence - Alternative modelling of cost reflectivity –** As part of the CMP213 process, P E Baker produced analysis for SSE using a simple 2-bus single circuit model. *"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*

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[8] CMP268 Code Administration Report page 159. Original source: CMP213 Final CUSC Modification Report Volume 1, 4.38

[9] CMP268 Code Administration Report page 160. Original source: CMP213 Final CUSC Modification Report Volume 2, Annexes, 4.135

[10] CMP268 Code Administration Report page 161. Original source: 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

methodology."[11] Baker also concludes that "*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*." (Baker 5.1). Importantly, when there is a high proportion of low carbon generation behind a transmission network boundary, then the TNUS charges faced by Carbon generators in that area become very close to the pre-CMP213 baseline, so <u>in that specific scenario</u>, the defect which Baker identified within the pre-CMP213 baseline of providing a "perverse" price signal also applies to the current baseline. This is the same defect which Poyry identified within CMP213 as described above. CMP268 would therefore correct this existing defect in the CUSC.

6. **Evidence - From NERA/ICL for RWE –** Cost reflectivity Vs LRMC – As part of the CMP213 process, RWE procured analysis from NERA/ICL, entitled 'Assessing the Cost Reflectivity of Alternative TNUoS Methodologies' (February 2014) 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.[12] The NERA/ICL report stated that "*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.*" The report also stated that *"[CMP213} WACM 2 and the status quo methodologies [pre-CMP213] 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."* In this regard the LRMC analysis from NERA/ICL further supported the position that the current baseline applies TNUoS charges which are too high for low load factor peaking plant located behind transmission network boundaries which are dominated by low carbon generation and therefore that the defect corrected by CMP268 would result in TNUoS charges for Conventional Carbon plant in those circumstances which are more cost reflective than the CUSC baseline.

During the CMP268 Workgroup process, SSE presented to the Workgroup some additional new analysis. This is included on the CMP268 Code Administrator Consultation (pages 139 to 151) and summarised below.

1. **Resulting Year Round tariff comparison of SQSS, CMP268 and Baseline –** This new analysis was effectively a refresh of the analysis and approach which P E Baker previously provided as part of the CMP213 process (see above) comparing the

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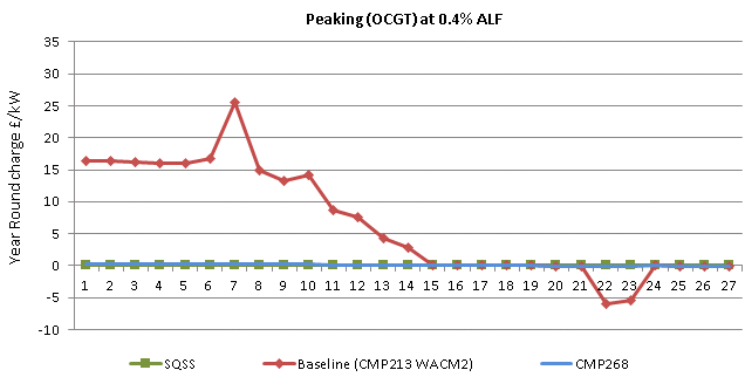
[11] CMP268 Code Administration Report page 164. Original source: Baker March 2014 5.2.3, Review for SSE of Poyry's Report to Centrica Energy "Review of Ofgem's Impact Assessment on CMP213, P E Baker, March 2014.https://www.ofgem.gov.uk/sites/default/files/docs/2014/04/review_for_sse_of_poyrys_report_to_centrica_energy_titled_review_of_ofgems_impact_assessment_on_cmp213_0.pdf

[12] CMP268 Code Administration Report page 165. Original source: http://www.nera.com/content/dam/nera/publications/2014/CostReflectivityReport.pdf

resulting TNUoS tariffs with the costs derived from the SQSS. This new analysis simply quantitatively and graphically illustrated economic principles which had already been previously discussed within the CMP268 Workgroup. With this in mind, the results of this analysis should be unsurprising to someone familiar with the TNUoS tariff methodology, although the graphical presentation can make it easier to explain. The analysis was presented in the CMP268 Workgroup report (pages 139 to 142) for a selection of different technology types, although to avoid duplication, only the graph for "Peaking (OCGT) is shown below. This analysis shows that compared with the costs implied by the SQSS scaling factors, CMP268 would result in TNUoS tariffs which were more cost reflective for Conventional Carbon generators (in particular low load factor peaking generators) and as cost reflective for low carbon generators. Importantly, in circumstances where CMP268 differs from the SQSS scaling factors, this is in scenarios where CMP268 would be more cost reflective of a full detailed CBA, therefore still more cost reflective of the actual costs caused by different types of generators.



2. **Empirical evidence that Conventional Carbon generators do tend to operate in a way which is consistent with CMP268 –** Within our CMP268 Workgroup Consultation response, SSE submitted new empirical evidence of recent generator dispatch decisions[13]. The results of this analysis were as expected and should not surprise someone familiar with the operation of the GB wholesale electricity market. In summary, the results are consistent with the key principles which were behind the original concept of sharing; introduced into the CUSC by CMP213; and the results are consistent with the proposal that CMP268 would further improve the cost reflectivity of the TNUoS charging methodology compared with the CUSC baseline.

3. **Illustration of the feedback loop created by the Baseline application of the Not Shared Year Round tariff element -** Within our CMP268 Workgroup Consultation response, SSE submitted new analysis using the National Grid published TNUoS Transport model to illustrate how the TNUoS tariff paid by different types of generator would differ in different scenarios[14]. This analysis addressed discussions which had previously taken place within the CMP268 Workgroup discussions and also

[13] CMP268 Code Administrator Consultation pages 143 to 147

[14] CMP268 Code Administrator Consultation pages 148 to 151

addressed by previous analysis submitted to the Workgroup by SSE[15] as originally conducted by Poyry (for Centrica) and P E Baker (for SSE). The results of this new analysis were as expected and should not surprise anyone familiar with the way the TNUoS tariffs are calculated. However, the graphical representation of the quantified tariffs provided in our evidence submission to the Workgroup are useful to help focus discussion. The results clearly illustrate the issue previously discussed in detail, namely that within the CUSC baseline charging methodology, the Year Round Not Shared tariff tends to dominate the economic price signal faced by low load factor peaking plant such that it tends to drown out the price signal from the Peak Security tariff. This tends to result in the perverse outcome that even if a low load factor peaking plant in the North may reduce the cost of the transmission network; by incrementally avoiding the need to reinforce the transmission network according to the SQSS Demand Security criteria; this cost reflective Demand Security price signal will tend to be drowned out so this economically beneficial investment is unlikely to take place. This inefficient economic outcome occurs because the baseline Year Round Not Shared tariff would result in a much larger charge to that peaking plant because the CUSC baseline TNUoS charges peaking plant as if it caused almost the same high constraint costs as a wind farm in the same location, while in practice that low load factor peaking plant may cause little, or no incremental constraint cost at all, therefore cause little to no economic justification for incremental transmission network investment.

Each of these sets of economic analyses takes a different approach to considering the issues related to sharing, although they all point to the same conclusions: firstly that CMP213 WACM2 is substantially more cost reflective than the pre-CMP213 baseline and secondly those same sets of analysis also support the conclusion that the implementation of CMP268 would result in the current CUSC baseline charging methodology becoming even more cost reflective.

5. Better meets CUSC objective “a” – Effective competition

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.

[15] CMP268 Code Administrator Consultation, Proposers Presentation 3.1 to 3.31 and pages 152 to 167

6. Better meets CUSC objective “c” – Developments in transmission licensee’s transmission business

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

7. Better meets CUSC objective “d”

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.

8. Better meets CUSC objective “e”

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.

Q2 Do you support the proposed implementation approach? If not, please provide reasoning why.

Yes, we support the proposed implementation approach for the reasons described in the Code Administrator Consultation report.

Q3 Do you have any other comments?

The comments below include our responses to some of the specific issues raised by other respondents to the CMP268 Workgroup consultation. The points raised by other consultation respondents are shown bold in blue, while our response to those points are detailed in the bullet points below.

EDF – SSE comments regarding EdF's consultation response

EdF claim there was too little time for an evidence based reopening of CMP213

- We are not reopening CMP213
- Same CMP213 analysis and evidence is being used for CMP268. If the evidence was good enough for CMP213, then it is good enough for CMP268.
- CMP213 was, by its very nature, far reaching and comprehensive covering, as it did, lots of different areas. By contrast, CMP268 is very focused.

EdF claim there was an insufficient number of meetings

- The Workgroup had more than the original timetable.
- Given the urgent nature of the proposal, which Ofgem recognised, we need to do the best we can with the time available.

EDF claim that it is not practical for parties to commission their own analysis, especially given there are "29 "live" CUSC mods.

- Our evidence is fairly clear – no further analysis is needed
- We note that the latest (date of issue 21st October 2106) CUSC Progress Report lists just eleven 'live' CUSC Modifications[16] (excluding CMP268 itself, which makes twelve in total).
- Notwithstanding that, our evidence is clear – no further analysis is needed.

EdF referred to a quote from the CMP213 Ofgem decision letter paragraph 1.15 –

- This quote from Ofgem is only a summary description of Diversity 1, this quote does not help the case either way. It does not say "all" plant (as seems to be being inferred by EdF), or "only low carbon".
- It cannot be taken as commenting on CMP268 because that was not the comparison Ofgem were making at the time they wrote their summary description (of another Modification, CMP213).

[16] CMPs 250, 261, 262, 264, 265, 266, 267, (268) 269, 270, 271 and 274.

EdF noted that the bid prices graph not repeated –

- This was a part of the justification for splitting plant into "Carbon" and "Low Carbon". In respect of CMP268, this analysis and this classification is not in question and does not need repeated. That having been said, we have looked at it and the answer is the same, as presented above.

EdF suggest that the "defect" was explicitly addressed during CMP213and Ofgem chose Div1

- The defect was not addressed during CMP213
- <u>There was never a "CMP268 like" alternative on the table when CMP213 was submitted to Ofgem</u>. Ofgem could only pick between the options which were available to it at the time. The "CMP268 like" option was not available for Ofgem to opine on at that time.
- The relevant question is whether CMP268 is better than the (current) CUSC baseline.

EdF suggest reopening a single issue within the overall framework of diversity is unjustified

- It is justified as the CMP268 defect is that the CUSC baseline is not cost-reflective and impacts on competition - and has no impact on other aspects of diversity
- It is in the nature of CUSC mods to be incremental and to change as little as only one element of the CUSC at a time rather than the hundreds of pages of the CUSC.

EdF quote the CMP213 Ofgem decision and outline that the CMP213 solution was partially driven by a desire for simplicity on the part of Ofgem (and to some extent this was a reflection of the deliberations of the Workgroup

- Our contention is that the CMP268 change being outlined here adds little or no complexity to the transmission charging methodology and the argument that it is overly complex simply ignores the methodology as proposed and tries to link it to a far more complex methodology that would have been based around forecasting actual bid prices for all plant in a transmission charging zone. The CMP268 proposed methodology retains the simplicity aspect of CMP213 but corrects a clear oversight regarding the rationale behind the application of the sharing concept to the year round methodology .
- It is important to remember that the key question is whether or not CMP268 is <u>**better than CUSC baseline**</u> rather than is CMP268 the ultimate solution.
- **EdF's argument here is a false dichotomy comparing "all the factors"** – CMP268 does not attempt to incorporate "all the factors".
- **Complexity** - CMP268 does not introduce "considerably more complexity"
- **Transparent** – CMP268 is no less transparent than the CUSC baseline.
- **Difficult to forecast** – CMP268 is no more difficult to forecast than the CUSC baseline.
- **"CMP268 like" alternative was not on the table at the time of CMP213**

EDF claim that the current signal increases the incentive for carbon plant to locate in areas with high proportions of low carbon plant

- This is a misrepresentation of how parties respond to price signals.
    - Price signals don't work in the way EdF suggest. Instead generation developers react to <u>**relative levels, not absolute changes per se**</u>.
    - Generators are not swayed by getting a bargain 20% off a given charge. Rather they are interested in the level of transmission charges relative to the level of transmission charges in other areas. The CUSC baseline approach of charging Conventional Carbon 100% of the Not Shared Year Round element makes their TNUoS charges relatively more expensive (in positive charge zones) compared with more diverse zones, so the CUSC baseline

approach obviously results in new Conventional Carbon generators being relatively less likely to locate (and existing generators more likely to close) in a non-diverse zone than they otherwise would if their ALF was applied to their whole Year Round tariff.
  - Properly functioning market provides price signals that incentivise participants to move towards the equilibrium; i.e. the further the current market position becomes from the equilibrium, the stronger the price signal should become to move back closer towards the equilibrium. However, the baseline approach of charging 100% of the Not Shared Year Round tariff element does the opposite of this. This is because if the market starts from a stable equilibrium position, but is then disturbed to move incrementally towards one of the extremes (towards either more, or less diversity) , the stronger the Year Round Not Shared price signal then becomes to move even further in that direction (i.e. even further away from the starting equilibrium and even further in which ever direction the initial disturbance happened to point).
  - <u>This effect is further demonstrated in the new analysis which SSE provided within the CMP268 Workgroup Consultation response.</u>
- Our contention is that in areas on the transmission network with increasing low carbon plant – which is the true driver of diversity regarding year round charging – the sharing offered by carbon plant does not decrease as the diversity decreases but that the transmission charging method affects charges applied to carbon plant as if it does. This has the impact of decreasing the incentive for existing carbon plant to remain connected to the transmission network– which in effect reduces the availability of low-cost bids in the GB wholesale electricity market)
- **EdF suggest that the (Proposer is neglecting that) Generators base their investment decisions based on the tariff <u>after</u> the decision –**
  - The Proposer is not neglecting this and it is true that Generators do base decisions on what they expect transmission tariffs to be after their decision. However, this observation is irrelevant, as it does not change the effect of the defect described by the Proposer.
  - This observation does not counter the fact that if the penetration of low carbon generation in positive transmission charging a zone increased, then the incremental change in the Year Round Not shared tariff would tend to provide an incrementally stronger relative price signal (compared with the price signal in other transmission charging zones) for an existing peaking plant to close and/or for a potential new entrant peaking plant to locate somewhere else instead.
  - This observation from EdF does not help a generator making a closure decision because that generator does not care if the Year Round transmission tariff will become more expensive after they close because the generator will no longer exist, so they will not have any financial exposure to the subsequently higher tariff.
    - However, generators who do care include any other remaining Conventional Carbon generators who would be left to face the higher Year Round Not Shared charge and would therefore be left to face an incrementally even stronger relative price signal to close compared with the price signal experienced by Conventional Carbon generators in other cheaper transmission charging zones
    - The other group of generators who would be affected by this would be potential new entrant Conventional Carbon generators. If they were previously considering investing in the relevant transmission charging zone (already taking into account the impact their decision would have on diversity and tariffs), then the CUSC baseline application of the Not Shared Year Round element would tend to make them incrementally less likely to invest in that zone after a previously existing Conventional Carbon generator had already closed because the starting point for the diversity in that zone would

be incrementally worse, so the starting point for the relative cost of the Not shared Year Round tariff would also be incrementally worse.

▪

EdF claim that SO considerations mean that the carbon plant in areas with high concentrations of low carbon plant will run ahead of the levels that would be predicted taking market prices and constraint costs only into consideration

- **This is not an incremental price signal** – Even if some running is needed during low net demand periods, this is not an incremental price signal, so should not be used as the basis for a TNUoS price signal for incremental investment/closure.

EdF present "evidence" that claims to demonstrate that Pump Storage and gas generation compete with wind for transmission capacity rather than share

- Our evidence demonstrates that EDF evidence does not give a substantial demonstration of "no sharing" having occurred)
- **EdF claim more running in the 10% windiest periods** - **See SSE evidence:**
    - Response in Workgroup report - it is net demand that matters, not windiness alone.
    - See additional evidence in the SSE Workgroup consultation response.
- **EdF claim that the "Proposer contested the analysis on the basis that PS provides inertia during pumping"** – This statement is attempting to put misleading words into the Proposer's mouth –By contrast, it was EdF that added that line to which they refer (regarding Pump Storage providing inertia during pumping) into the CMP268 Workgroup report. A question of whether Pump Storage may or may not provide inertia during pumping was not part of the Proposer's criticism of EdF's analysis..
- **EdF imply criticism of the suggestion that their analysis of Peterhead data should be disregarded –** By contrast, the view that this analysis should be disregarded was provided with good reason:
    - **The available data was based on less than 3 weeks** running out of the whole year; i.e. less than 6% of the time.
    - **That running based was on the operational needs associated with commissioning and testing of the steam turbine** following extensive maintenance work at Peterhead rather than for direct market purposes
    - **That running was restricted to SBR dispatch requirements** - So almost all of the periods identified in the top 100 (periods exceeding TEC of 400MW i.e. 200MWh per HH) were specifically **required to avoid periods of peak demand**. This is why the data may appear counterintuitive and was therefore, in our view, justified in being discarded from the analysis.
    - See new SSE analysis - Our data for 2013/14 is more representative
    - Note lack of scale of "Scotland net position" data in the graph provided by EdF which may be misleading and distort the interpretation of the analysis.

EdF claim that CMP268 provides a competitive advantage to a minority of generators without improving cost reflectivity

- We say that to not pursue CMP268 subjects some generators to a competitive disadvantage that is unjustified and is not cost reflective and is likely to have detrimental impact on competition, and thus on customers, if left unchanged

EdF claim that "it has not been proven that CMP268 improves the cost reflectivity…".

- *We believe that our evidence comprehensively shows with clarity that CMP268 improves cost reflectivity, compared to the CUSC baseline*).

RWE – SSE comments regarding RWE's consultation response

RWE claim that introduction of sharing to the non-shared component of the tariff undermines the approach adopted for generation tariffs under CMP213. They claim that CMP213 "method 1" clearly establishes the principle that sharing between carbon and low carbon generators up to a defined level is based on the ALF, and that beyond this level the capacity of the generators in the zone determines the non-shared investment signals…

- In this section of their response, RWE are simply describing how the CUSC baseline currently works, but this description fails to address the key question of whether CMP268 is better than the CUSC baseline.
- We contend that whilst this can be shown to be the case for low carbon generators it is clearly not the case for Conventional Carbon generators and that for Conventional Carbon generators the ALF is still relevant beyond the defined level.

RWE claim that they "have seen no new evidence that CMP268 is more cost reflective than the current baseline."

- We say that RWE simply ignore the evidence that we have presented – rather than challenge it and that this does not amount to a credible response
- **RWE does not attempt to challenge any of the extensive evidence the Proposer provided to the CMP268 Workgroup from CMP213 (Previous analysis).** Other CMP268 Workgroup members have also chosen to ignore this previous analysis and in this way avoid bringing attention to it.
- **Notwithstanding the above, in this Code Administration Consultation new evidence has now been provided.**

RWE are concerned that the timetable prevents detailed consideration .

- We say that there has been adequate time and that the time available is very similar to the time that was concerned with this particular issue during the CMP213 process

Uniper – SSE comments regarding Uniper's consultation response

Uniper claim the mod arises from a misunderstanding of CMP213. They outline that scaling of year round charges by ALF reflects the relationship observed between load factor and volume of constraints. They additionally outline that the introduction of not shared element reflects the fact that sharing is dependent on diversity within a zone and that diversity can be driven as much by having tool little carbon plant in a zone as by having too much low carbon plant in a zone.

- Uniper goes on to describe the CUSC baseline only.
- None of the material Uniper presented undermines CMP268.

Uniper claim that "Sharing breaks down when SO is less likely to be able to access bids from carbon plant", thereby implying that carbon plant are somehow responsible for causing the sharing to break down by means of their absence during times periods of constraint, further implying that those conventional carbon who are not generating during those periods should be charged a higher TNUoS price for not generating

- Uniper appear to be confusing the contributions to sharing of installed **capacity** compared with **generation dispatch**. Different generation capacity will obtain the greatest mutual sharing benefit if they generate at different times; i.e. they do not generate at the same time as each other and the TNUoS which they pay is a function of their capacity. It is therefore the relative shortage of Carbon **capacity** which leads to low carbon generation capacity being unable to obtain a full sharing benefit, and it is not (contrary to Uniper's assertion) the relative shortage of Conventional Carbon **generation dispatch** which leads to this effect.
- This argument from Uniper is illogical because if a conventional carbon generator is not running during constraint periods, then while it may not be available as a source

of low cost bids to be constrained off, it is not contributing to the cause of constraints so it is not causing SQSS Economy Criteria based transmission network investment. By contrast, Uniper appear to imply that Conventional Carbon generators should be given a greater credit for sharing (lower TNUoS tariffs) if they did actually generate during periods of constraint just so that the SO could make use of their low cost bid prices to constrain them back off again, which is clearly illogical. This comment from Uniper is neglecting the fact that the degree of sharing is a function of both (i) the price of bids and (ii) the correlation of generation with periods of constraint. This mean the greatest contribution a Conventional Carbon generator can make to improving sharing of the transmission network is to not generate at all during periods when constraints may take place because then the SO does not need to incur any cost at all to bid them off. By contrast, if the Conventional Carbon generator was generating during a period when constraints were taking place, then the SO could still make use of their low cost bid price to constrain them off at a relatively low cost, however this relatively low cost would still be more expensive than the alternative of not having to constraint them off at all because they were not generating in that period to start with.

- It is the **absence** of Carbon plant that causes sharing to break down (for the Low Carbon plant), not the presence of it Carbon plant. The Carbon plant capacity which is there is continuing to sharing and is helping the Low Carbon Plant to share.
- **Principle of cost reflectivity –** You charge existing generators for the costs which those existing generators cause because of the fact that they exist. If Uniper claim that Conventional Carbon generation **capacity**, by their absence, cause insufficient carbon capacity for the low carbon generators to share with, then it would imply that it should only be that Conventional Carbon capacity which is absent which should pay the higher TNUoS charge (which is clearly nonsense, because the TNUoS charging methodology cannot charge non existent generation capacity for not being there). By contrast, that Conventional Carbon generation capacity which does exist is fully contributing to sharing the transmission network, so its contribution to sharing should be fully recognised in the TNUoS charges which it faces.

Uniper claim "Therefore, diversity can be driven as much by having too little carbon plant in a zone as it can by having too much low carbon plant in a zone. " [emphasis added] –

- This highlights the defect (that CMP268 seeks to address) well and highlights the nonsense of this counter argument. If there is a starting point of high diversity where the Carbon plant is sharing well with wind, then why would adding more wind to that zone make the existing Carbon plant in that zone share any less than it was previously? - In reality it would not because from the point of view of the Conventional Carbon plant, it does not matter if it has enough wind to share with, or more than enough wind to share with because either way, the Conventional Carbon generation continues to be able to fully share. By contrast, in this example, when more wind is added to the transmission charging zone, then it is only that wind which becomes less able to share with the existing Carbon generation.
- In their response, Uniper fail to realise that the degree of sharing does not need to be the same for both parties of the sharing arrangement. It may be helpful to explain this point through an analogy: *Say two groups of people come to a barbeque, if there is a higher level of diversity, then we may see 10 people bring 2 buns each (equivalent to low carbon) and 10 people bring two sausages each (equivalent to carbon). Individually no-one person can make a hotdog, but between them they can share such that the people with the buns give up one bun and the people with the sausages give up one sausage, so everyone ends up with a hotdog and everyone is happy. However, if there is a low level of diversity, then we may see 15 people turning up with buns (too much low carbon), but only 5 people turning up with sausages (not enough carbon). In this scenario, the people who bring sausages can still obtain a full sharing benefit by sharing one of their sausages in exchange for a bun, so all of the people who brought sausages (carbon generators) still end up with*

a hotdog each, so they are all happy. By contrast it is the group who brought the buns who, collectively, are not able to obtain the full benefit from sharing because it is only the people who brought the buns who will, on average, be left with less than one hotdog each.

Uniper outline that the CMP213 solution was partially driven by a desire for simplicity on the part of Ofgem (and to some extent this was a reflection of the deliberations of the workgroup – Quotes Ofgem decision letter 2.17

- This is the same erroneous point as that made by EdF
- Our contention is that the change being outlined here adds little or no complexity to the transmission charging methodology and the argument that it is overly complex simply ignores the methodology as proposed and tries to link it to a far more complex methodology that would have been based around forecasting actual bid prices of all plant in a transmission charging zone. The proposed methodology retains the simplicity of CMP213 but corrects a clear oversight regarding the rationale behind the application of the sharing concept to the year round methodology) .
- We again highlight that the key question is whether or not CMP268 is **better than CUSC baseline**.
- **This is a false dichotomy comparing "all the factors"** – CMP268 does not attempt to incorporate "all the factors".
- **As regards the contention of added complexity** - CMP268 does not introduce "considerably more complexity"
- **As regards the contention of loss of transparency** – CMP268 is no less transparent than the CUSC baseline.
- **As regards to the claim that CMP268 will be more difficult to forecast** – CMP268 is no more difficult to forecast than the CUSC baseline.
- **"CMP268 like" alternative was not on the table at the time of CMP213**

With respect to CMP268 Uniper then claim that SSE is confusing the impact of diversity with the impact of being in an expensive part of the network on the economics of closure of carbon plant. They outline that in their view, the incremental impact of the current year round charge is correct – i.e. year round charges reduce as more carbon plant is added therefore there is a signal to invest in more carbon plant in a zone as the volume of low carbon plant increases . They contend that the problem that SSE is trying to fix is not addressed by changing TNUoS as it is the underlying economics of the carbon plant that is the root cause.

- We have outlined above, in the section covering EdF's response, our response to these same points
- Contrary to Uniper's contention, the Proposer is not referring to Peterhead specially, and is not referring to simply the effect of the Year Round tariff being expensive. By contrast, the Proposer is referring to the broader principles of how the Not Shared Year Round tariff element works.
- Our contention is that the increase in the transmission charge to a carbon plant as the low carbon plant proportion increases behind a transmission network boundary is not cost reflective – this is relevant to transmission charging for existing and new plant and can in certain circumstances lead to non cost reflective outcomes.

Uniper contend that CMP268 would result in a non cost reflective charge as it represents a "change which does not reflect the logic of why the Shared and Not Shared tariffs were put into place."

  - We contend that the Shared and Not Shared were put in place to reflect the fact that sharing by low carbon plant reduces as the low carbon proportion exceeds a threshold value – this is not the same as saying that sharing by carbon plant reduces as the low carbon proportion exceeds a threshold value.

Uniper quote from para 4.36 of CMP213 Workgroup Report

- **Uniper misinterprets the quotes:**
  - ***"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."*** –
    - This is not evidence against CMP268
    - The quote does not say what Uniper claims it says as they (Uniper) misrepresents the quote by interpreting it as meaning:: "*"the TO would invest to meet the total amount of plant in a zone, both carbon and non carbon as sharing in these circumstances [where this type of plant is dominant] is ineffective in reducing investment costs because of the low amount of lower cost bids available."*
    - By contrast, the quote Uniper refers to is actually making the point that the TO builds sufficient transmission network to accommodate the "expensive action plant" in contrast to the following sentence in the same paragraph (described further in the next bullet point below). By contrast, the original quote is simply saying that the TO may build "at or very close to the total generation capacity in the area concerned" but only because, by definition, the "expensive actions" plant by themselves are by definition "at or very close to the total generation capacity in the area concerned".
- **Uniper conveniently ignores the following sentence in the same quote:** "*Likewise, **<u>where the costs of constraining plant off was [sic] relatively low</u>**, the general assumption is that the transmission network capacity would **<u>not be very close</u>** to the total generation capacity in the area concerned and this would, therefore, mean lower transmission network investment." [emphasis added].* The cost of constraining off Conventional Carbon plant is always relatively low, so for this type of plant, this second criteria always holds.
- Uniper here are overplaying the logic of the CMP 213 Workgroup and ultimate decision – the same section of the CMP213 Workgroup report that they refer to goes on to state "where the costs of constraining plant 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." – This is precisely the issue that CMP268 is seeking to address – carbon plant, even in areas with high non carbon penetration will still generally bid low prices and therefore the impact of it on transmission costs will reflect its load factor and as such it is an improvement to the transmission charging methodology to modify the year round not shared tariff element by the ALF of carbon plant – this contention has been backed up with the operational data evidence that SSE has presented.

Uniper conclude that it would be incorrect for an ALF to be applied to the Not Shared charge for carbon plant as it is not justified and would be less cost reflective than the baseline and that this would introduce a cross subsidy that would distort the wholesale market and the capacity market.

- Our contention is that applying an ALF to Not shared charge is consistent with the SQSS notion of sharing, it is consistent with the CMP213 justification for sharing and as such is more cost reflective than the CUSC baseline – the defect which we are trying to address was arrived at by accident when seeking simplicity and in doing so oversimplifying – and to not address this via the very simple means proposed by CMP268 will allow an existing distortion to the GB wholesale electricity market and the capacity market to endure.

Uniper claim that the distributional effects of CMP268 are significant and state that the proposal was "cleverly designed to give a significant cost reduction to only a few stations at the expense of the rest of generators".

- (*There is nothing "clever" about the CMP268 proposal – it is simply a product of the current distribution of low carbon plant and carbon plant that results in only a few plant being affected significantly by the defect in the CUSC. Uniper's inference is that this in someway undermines the case for change – however the opposite is surely true – a small number of generators currently face a significant distortion and surely it is reasonable that the approach is changed in a way that makes the transmission charging methodology adhere better to its underlying core principles (of cost reflectivity) even if the majority of parties might oppose it as they stand to gain by maintaining the (defective) status quo. Or is it to be the case that only CUSC changes which benefit 'the many' not 'the few' are to be taken forward?*)
- The fact that it could make the difference between a generator getting a capacity contract and it not (rather than being in some way a case against as Uniper claim) is exactly why there is an undeniable case for change.
- By contrast, the distributional effects are relatively small. Only 3 stations directly benefit, while only one directly disbenefits. The indirect impact on the residual is relatively small. Demand is not affected at all by the CMP268 proposal.

Drax – SSE comments regarding Drax's consultation response

Drax claim that due to such a short timescale, they do not believe that the Workgroup has had sufficient time to properly assess the proposal.

- Workgroup members were all very involved in CMP213, so the issues are very familiar to them.
- Workgroup can only do the best it can with the time available.
- CMP268 is not complicated.

Drax claim 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.

- CMP268 does not add complexity, or reduce transparency, it is not a barrier to entry

Drax claim that 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.

- CUSC open governance is normally incremental change. To delay every possible improvement to a defect in the CUSC until such time as (in the view of some parties) a more fundamental review that looks at all the elements can take place is not only unreasonable but also strikes at the core of principle of CUSC open governance that changes can, and should, be raised as soon as possible – indeed this very point was highlighted by Ofgem in its decision letter granting urgency for CMP268.
- It is not possible, or necessary to re-open everything for every change
- The simple question here is whether the incremental change of CMP268 is any more cost reflective than the CUSC baseline – we have shown this comprehensively to be the case.

Drax claim that to properly assess the benefit of change to the current methodology, new, comprehensive analysis would need to be undertaken.

- No, as above, it is an incremental change and extensive analysis has already been produced.
- Evidence and principles for CMP268 was largely laid out during CMP213 as described by the Proposer

Drax state that they 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, <u>the TNUoS charging arrangements may not provide efficient signals for siting flexible plant in the North and particularly Scotland</u>. <u>A change to the charging arrangements should be considered to rectify this probable defect</u>, however, CMP268 is probably not the answer and the issue should be addressed by a wider charging review.

- Drax appears to agree that the defect exists.
- The key question is whether CMP268 is better than the CUSC baseline with respect to this defect. It is not appropriate to compare CMP268 with some hypothetical "wider charging review" which may or may not actually take place and, even if it were to take place, the delivery timescales (together with its terms of reference) are unclear.

Drax state that they believe that it <u>cannot be demonstrated</u> that CMP268 improves cost reflectivity of the transmission charging methodology and possibly only acts to redistribute costs between generators

- Proposer has presented compelling evidence for the better cost reflectivity that CMP268 provides. Drax appears to choose to ignore it and makes no attempt to provide consideration of the evidence that has been provided.
- Redistributing cost is better if it corrects a pre-existing discriminatory distortion within the CUSC baseline as, on the contrary, to maintain a non-cost reflective transmission charging methodology (within the CUSC baseline) will itself continue to redistribute costs inappropriately between generators.

Drax suggest that 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.

- The Workgroup report clearly refers to the £0.17/kW additional to the residual since that is where Drax themselves obtained the number in their own quote: **"** *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*."
- The Workgroup report was subsequently updated to provide an even clearer explanation of the analysis to avoid any risk of confusion. This indirect residual effect is part of the normal operation of the ICRP transport model. The purpose of the locational transmission tariffs is to provide relative locational price signals.

CUSC Code Administrator 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 **03 November 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 included within the Draft CUSC Modification Report to the CUSC Panel and within the Final CUSC Modification Report to the Authority.

Respondent:	*Paul Jones paul.jones@uniper.energy*
Company Name:	*Uniper UK Limited*
Please express your views regarding the Code Administrator 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.). (e) promoting efficiency in the implementation and administration of the CUSC arrangements. *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).*

Code Administrator Consultation questions

Q	Question	Response
1	**Do you believe that CMP268 better facilitates the Applicable CUSC objectives? Please include your reasoning.**	No. What it does do is to provide a specific subsidy to particular plant which does not reflect the basis on which investment is made on the network or the rationale behind why diversity was introduced as part of CMP213. Therefore, it is detrimental to competition in generation, through distorting the wholesale market and capacity market, frustrating objective a). It also reduces cost reflectivity, working against objective b).
2	**Do you support the proposed implementation approach? If not, please provide reasoning why.**	No.
3	**Do you have any other comments?**	As well as the more in depth comments we made to the workgroup consultation, we have provided some further analysis in the attached document, attempting to address some of the deficiencies in the analysis provided by the proposer at a late stage in the workgroup consultation. This shows that the proposer's analysis is incorrect and that the real issue appears to be that there is a lag preventing the ALF for Peterhead from immediately reflecting its recent lower levels of running. This lag of course was an issue which was well known when CMP213 was assessed and implemented. It was also a solution which was vigorously defended by the proposer at the time.

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3 November, 2016

Further analysis of CMP268

This paper seeks to add to the analysis available to the Authority in order to assist its consideration of whether or not CMP268 should be implemented. It does not attempt to carry out a full analysis that would be needed to assess this issue thoroughly. Due to the truncated timescales for assessing the modification this has not been possible for us or the workgroup to carry out the full analysis required given the fundamental nature of the issue that the modification is seeking to address.

What the analysis below shows is:

1) The proposer is not correct in asserting that CMP268 would produce charges closer to those calculated by scaling the Year Round charges by the SQSS scaling factors. Our evidence suggests that the existing baseline is better.

2) That CMP268 simply provides a subsidy for a few stations, dramatically increasing the relative competitiveness of a subset of these, which is paid for by a small increase in charges to other stations.

3) The real issue that the proposer could perhaps complain about is the fact that its load factor at Peterhead has dropped dramatically, but this is not reflected in its ALF yet, due to the averaging nature of the calculation. This is an issue which was well understood at the time CMP213 was assessed and approved.

4) The proposer is incorrect to assert that after the implementation of CMP268, the stations that benefit from the modification would still be paying amongst the highest £/kW TNUoS tariffs of any generator in GB.

The proposer's latest analysis, provided in response to the workgroup report, calculated Year Round charges by multiplying both elements (Shared and Unshared) of the Year Round Charge by the scaling factors which would be used under the SQSS. It then compared these charges with those calculated under the existing methodology and CMP268 for various hypothetical ALFs. The intent of this was to show that CMP268 provided numbers which were closer to the SQSS numbers than the baseline.

When the workgroup discussed this analysis there was some disagreement about whether like-for-like numbers were being compared. The SQSS numbers are used to create a background to assess investments in the network and the ALFs are used for setting charges. However, if we were to assume the premise that a good solution to charging would be one which created charges which were close to those calculated using the SQSS factors, then we do not believe that the analysis which was undertaken by the proposer was carried out in the correct way to properly assess this.

When the economic investment criterion is used for the assessment of the investment needed on the system under the SQSS, output from generating stations is scaled by set factors. All plant of a certain type is scaled using the same factor. For instance wind plant has a scaling factor of 70%. Some factors are predetermined at a specific level, such as the wind example above, and the rest are scaled to make the model balance overall across the system. Critically, the scaling factor used is not set to a particular plant's ALF or a specific predicted load factor for a particular plant.

The proposer's analysis plotted what the charge would be in different zones for different plant types if the SQSS factor was multiplied by both the shared and non-shared Year Round tariffs. It then compared this with the charges for the baseline methodology and CMP268 using various hypothetical ALFs. The graphs attempted to show that, using those hypothetical ALFs, charges were closer to the SQSS under CMP268.

However, we did not understand why hypothetical ALFs were used for this analysis when actual ALFs are already being used at present to set charges. Therefore, we undertook some analysis to see how the charges were actually faring using real ALF data. To do this we used the spreadsheet which National Grid provided as part of the assessment of CMP268. This already calculated the charges which would apply under the existing baseline and compared them with those under CMP268. We also used this spreadsheet to calculate what the charges would be using the SQSS factors to scale both the shared and non shared Year Round charges as in the proposer's analysis.

We then calculated the difference between the SQSS scaled charges and those under the existing baseline. We also calculated the difference between the SQSS scaled charges and those under CMP268, in order to assess which methodology produced charges which were closer to those using the SQSS factors. The results of this are plotted in figure 1 below.

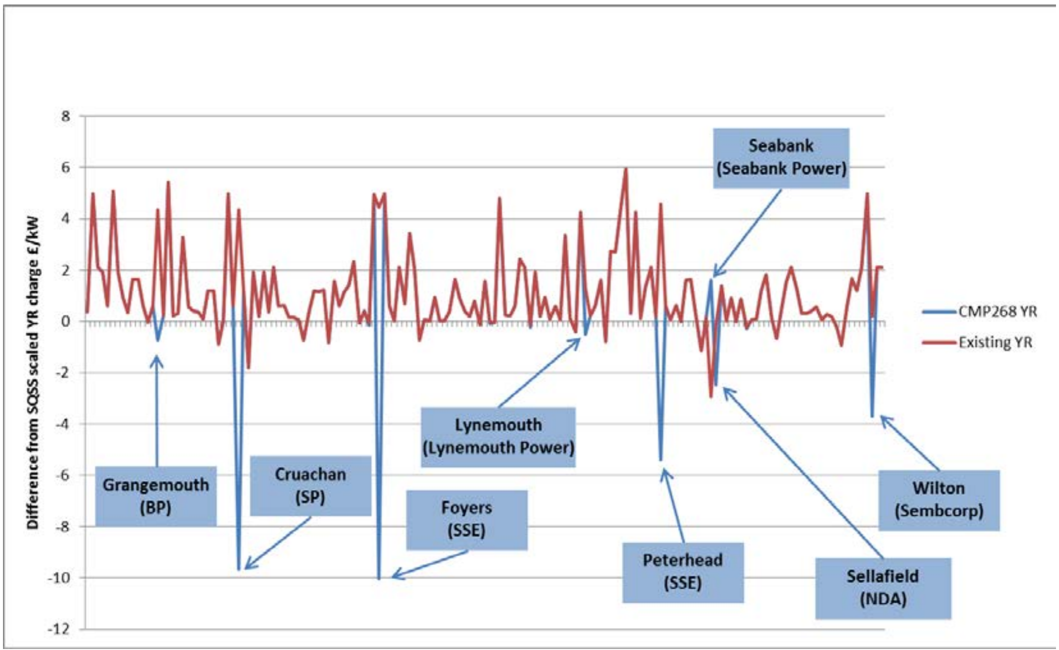

Figure 1: Difference from SQSS factor scaled YR charges, of charges calculated using Existing Methodology and CMP268

What figure 1 shows is that the existing methodology tends to produce Year Round charges which are not the same as those using the SQSS factors. Of course, this is not surprising given that the SQSS uses a generation class average and the ALF is specific to a plant. Some charges are reasonably close, but this is likely to be caused by coincidence rather than by design. This is also true for CMP268 which again is unsurprising. Given the design of CMP268, the charges for most stations are the same as for the existing baseline, so the differences from the SQSS are also the same in these instances.

However, what is also clear is that, when CMP268 does produce different charges, it generally does not bring charges closer to the SQSS scaled ones, which would reduce the difference to closer to zero in the chart above. Instead, it tends to pull charges down significantly so that they are well below the SQSS scaled numbers. Therefore, if you were to assume that the SQSS scaled numbers are somehow a measure of what's fully cost reflective, then CMP268 appears to make the charges less so than the baseline.

The benefit of using National Grid's model to undertake this sort of analysis is that you can also estimate what might happen to total charges, as it can calculate a new residual tariff when you scale the locational charges differently. The differences in the total charges from the SQSS scaled numbers are plotted in figure 2.

Figure 2 is essentially very similar to figure 1. However, what it does show is that in order to pay for the large reduction in charges for a few stations provided under CMP268, the charges for all other stations are increased slightly, generally moving them even further away from those values calculated using the SQSS scaling.

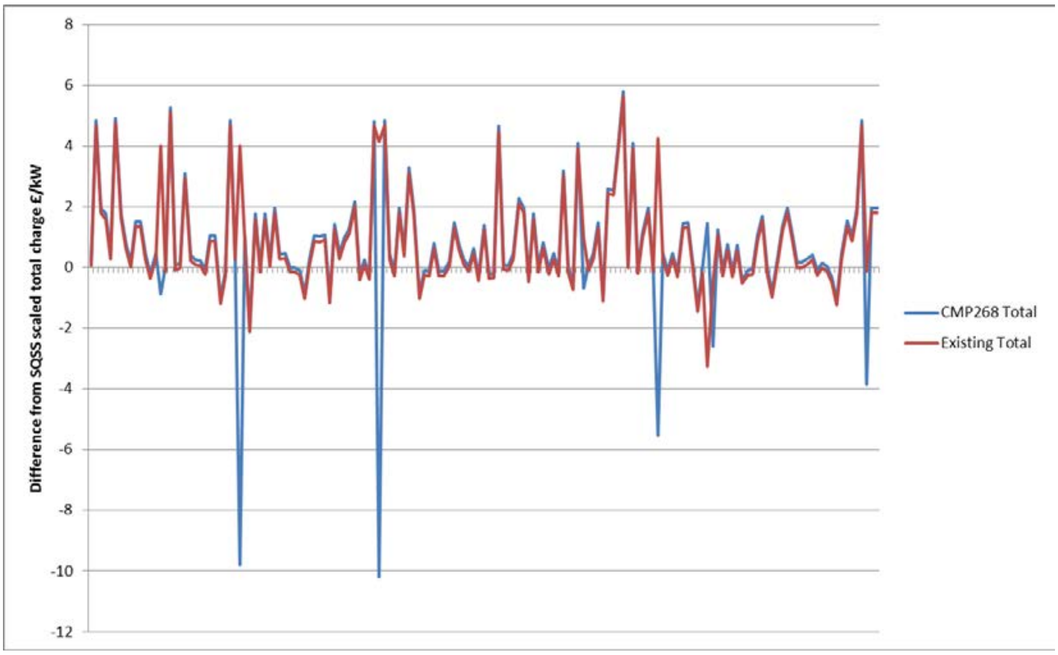

Figure 2: Difference from SQSS factor scaled total charges, of charges calculated using Existing Methodology and CMP268

Essentially, this shows that CMP268 doesn't move charges closer to the SQSS figure, but merely provides a cross subsidy to a small subset of stations which is funded by a small increase in charges to other stations. This improves the relative competitive position of these stations compared to the others, in some cases dramatically so.

We note that the proposer's analysis focused on looking at the charges for OCGTs and concluded that this showed that the charging was not correct for a low load factor CCGT too which would have similar running patterns. The analysis also specifically referred to the proposer's station at Peterhead. If we assume that the low load factor CCGT plant that they have in mind is also Peterhead, then we believe that the proposer may actually really have a problem with the fact that its ALF is relatively high compared with its actual recent running patterns.

We do not have up to date information on ALFs for next 2017/18 charging year, but we do have those used for 2016/17. If we look at Peterhead's ALF and compare it with the individual annual load factors which contributed to it, you see that the real issue for Peterhead is the lag imposed by the averaging used in the ALF calculation. Peterhead's individual annual load factors have reduced dramatically over the last few years, but its ALF is still held relatively high due to earlier years' performance.

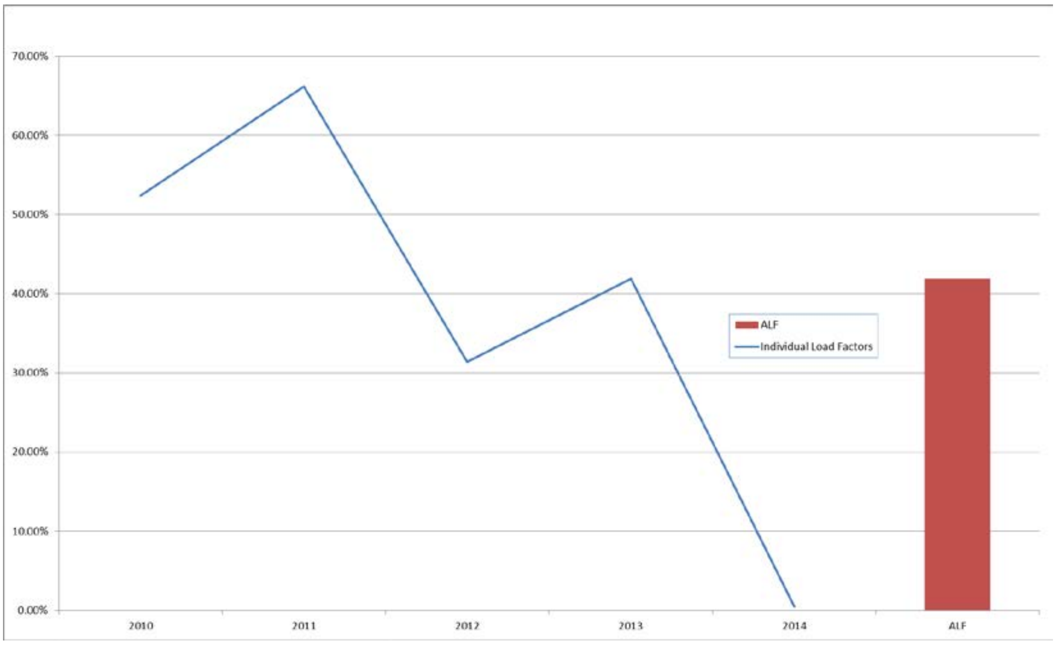

Figure 3: Peterhead's 2016/17 ALF compared with the constituent individual LFs

We would conclude that the principle issue for the proposer with the current methodology is that the ALF does not react quickly enough to its declining load factor at this station. This is an issue which was raised as part of CMP213 by those who felt that the use of ALFs was not the correct approach. It was well known and understood at the time and even led to a number of alternative options for calculating ALFs to counter its deficiencies. Nevertheless, on balance the Authority felt that the option to be implemented should include this method to calculate ALFs.

We have calculated what Peterhead's charges would have been had it used its last (2014) individual annual load factor rather than the full ALF. This would have brought down the charge by around £2.20/kW, rather than the somewhat disproportionate decrease under CMP268 of £9.95/kW.

Finally, we note that the proposer in part seeks to justify the large increase that CMP268 would provide for its station at Peterhead, as well as for a few other stations, as it feels that "*even after this reduction, they are likely to still be paying amongst the highest £/kW TNUoS tariffs of any generator in GB*[1]".

We have tested this theory as we considered that a £9.95 reduction in charges couldn't possibly occur without that station moving down the rankings on the level of £/kW charge it is exposed to. We therefore sorted the charges calculated under CMP268 and the existing baseline from highest to lowest, and plotted the resulting profile. This is shown in figure 4. As well as showing the two stacks we have also plotted where the stations that are principally affected by CMP268 would sit on each of the stacks.

What the graph shows is that under the baseline the affected generators are generally distributed along the range of possible charges. What CMP268 does is to generally pull down the charges of the affected generators; for a number to such an extent that they end up much lower down in the order.

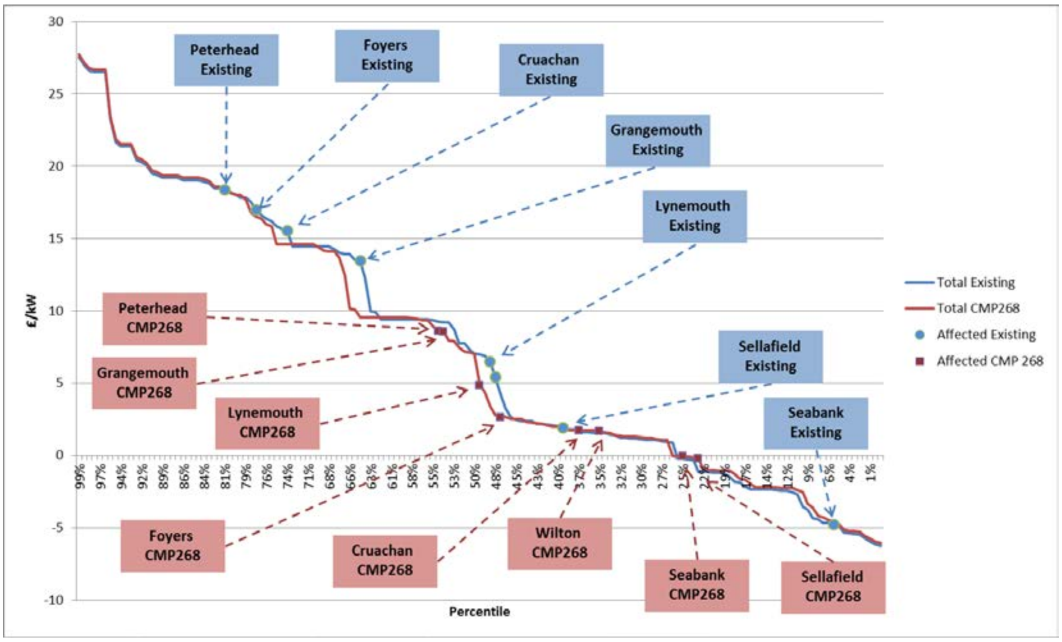

Figure 4: Total TNUoS tariff stacks for existing methodology and CMP268

For instance, Peterhead moves from occupying the 81st percentile under the existing methodology to the 55th percentile under CMP268. We would find it difficult to describe a generator that occupies that position to be "paying amongst the highest £/kW TNUoS tariffs of any generator in GB" although we accept that it is still within the highest half of payers. Peterhead is the highest charge of the affected generators, so the above statement could not apply to any of the other stations either.

Conclusions

- We believe that CMP268 would not provide charges that are closer to those which would pertain from Year Round charges being scaled by SQSS scaling factors, as asserted in the proposer's analysis provided to the workgroup

[1] CMP268 Code Administrator Consultation – para 4.34

consultation. This is because the proposer's analysis looked at hypothetical ALFs and failed to compare against ALFs which are being used in reality.

- CMP268 would provide charges which would be substantially further away from SQSS scaled charges for a small number of stations, effectively providing a cross subsidy, which is funded by all other stations. This would distort competition in favour of most of this plant, in some instances dramatically so.

- The real issue for the proposer's plant at Peterhead is that its ALF has not yet reflected the significant decrease in its load factor. However, this is a deficiency of the proposal which was approved by the Authority and was well understood at the time. We would note that the proposer not only accepted the decision to implement this modification proposal, but defended the Authority's decision during the unsuccessful Judicial Review case.

- We would not wish to imply that the correct decision would be to reduce the station's ALF as a solution to this modification. If this issue is to be addressed, a more fundamental analysis of the issue of sharing would have to be undertaken, which has not been possible given the truncated timescales allowed for the assessment of this modification.

- The proposer is also incorrect to assert that plant which benefit from CMP268 would still be paying amongst the highest £/kW TNUoS tariffs of any generator in GB. The analysis shows that all affected stations would be within the lowest 60% of charges which is due to the significant cross subsidy that the change would provide.

Annex 9 – 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:

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

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~~t~~he initial tariff for the Shared component is multiplied by both, the total forecast generation capacity and the ALF to give the initial revenue recovery:

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

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

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

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

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

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- 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

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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.

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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. 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

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. 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:

$$\sum_{Gi=1}^{n}\left(ITT_{\substack{GiYRNSN\\CC}} \times G_{Gi}\right) = ITRR_{\substack{G\,YRNS\\NCC}}$$

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

$$\sum_{Gi=1}^{n}\left(ITT_{Gi\,YRS} \times G_{Gi} \times ALF\right) = ITRR_{G\,YRS}$$

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

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-;

- 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.

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$$Local\ Annual\ Liability\ = Ch\arg eable\ Capacity \times Local\ Tariff$$

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Conventional –

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

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