Stage 03: Workgroup Report

Connection and Use of System Code (CUSC)

CMP251

'Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010'

What stage is this document at?

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

CMP251 seeks to better meet compliance with European Regulation 838/2010 by removing the error margin introduced by CMP224 and by introducing a new charging element to the calculation of TNUoS.

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

The Workgroup concludes:

CMP251 with majority that the baseline better facilitates the Applicable CUSC Objectives with note of support for WACM5.

Medium Impact:

Supplier, Generators

Contents

Any Questions?

Contact:

Ryan Place

Code Administrator

ryan.place@nationalgrid.com

07976794334

Proposer: George Moran – George.moran@britishgas.co.uk

About this document

This is the final Workgroup Report which includes the deliberations of the Workgroup, responses from the Workgroup Consultation and the final conclusions of the Workgroup.

Document Control

Version	Date	Author	Change Reference
1.0	13th April 2016	Code Administrator	Workgroup Report to Panel
2.0	21st April 2016	Code Administrator	Workgroup Report to Panel Workgroup member comments
3.0	1st June 2016	Code Administrator	Workgroup Report to Panel Workgroup member comments
4.0	15th June 2016	Code Administrator	Workgroup Report to Panel Workgroup member comments

5.0	23rd June 2016	Code Administrator	Workgroup Report to Panel

1 Summary

1.1 CMP251 was proposed by British Gas and was submitted to the CUSC Modifications Panel for their consideration on 28th August 2015. A copy of this Proposal is provided within Annex 1. The Panel determined that the proposal should be considered by a Workgroup and following the conclusion of a 20 business day consultation period report back to the Panel.

1.2 CMP251 seeks to remove the error margin in the cap on total TNUoS recovered by generation and introduce a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010 (Part B) with least impact on GB consumers.

1.3 Following the Workgroup discussions, as summarised in this report, this 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/CMP251/ along with the Modification Proposal Form

Workgroup Conclusion.

1.4 At the final Workgroup meeting, Workgroup members voted on the Original Proposal and the 7 WACMs: six of the Workgroup members voted that the Baseline better facilitated the Applicable CUSC Objectives, two Workgroup members voted for WACM5 and 1 Workgroup member voted for the original solution.

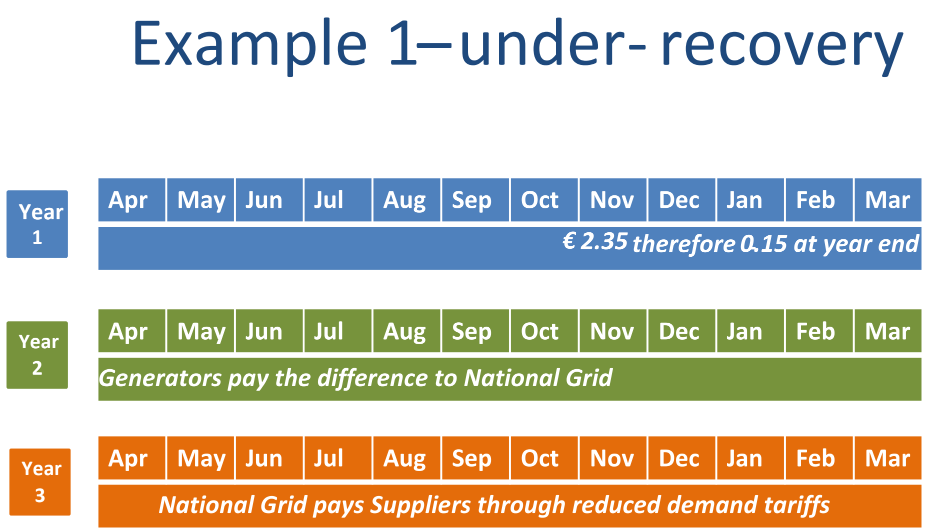
2 Workgroup Discussions

The Proposal

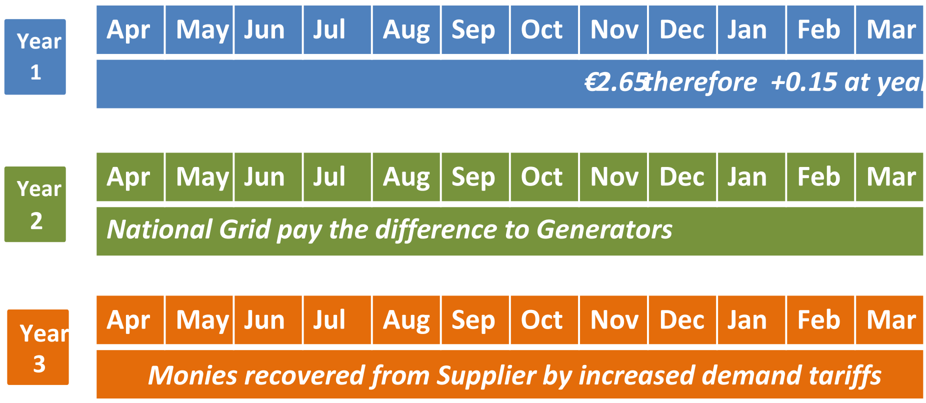
2.1 The Proposal can be found in Annex 1. In essence the modification seeks to refine the approach to compliance with the annual average €0-2.5/MWh range applicable in GB that can be recovered through transmission tariffs from chargeable generation defined in EU Regulation 838/2010 Part B , by removing the need for an error margin through the introduction of a reconciliation (if CMP251 is implemented).

2.2 The Proposer identified the defect as the error margin approach included within the current ex ante methodology (implemented into the CUSC via CMP224). The Proposer believes that this approach does not guarantee compliance with the Regulation and places a greater burden on Suppliers than necessary to comply with the Regulation. For example, the error margin used in the calculation to define the G:D split for Charging Year 2015/16 has been set by reference to €2.34/MWh (which includes the error margin for demand and revenue forecast error) rather than the maximum of the range, namely €2.5/MWh. The Proposer therefore suggests that the error margin should be removed.

2.3 The Proposer also outlined that an ex post reconciliation should be added to the existing process reconciling Generation shortly after the end of the Charging Year, and Suppliers the following Charging Year as shown in the diagram below:



Example 2 – over-recovery



2.4 The Proposer presented the benefits of the proposal to the Workgroup as:

(a) Certainty of Regulation compliance

(b) Minimising impact on the principles underpinning TNUoS tariffs

(c) Minimising the required transfer of costs from generators to consumers

(d) Provide predictability by providing a fixed cap for generators

(e) Predictability to Suppliers

(f) Removes the risk of changes in the error margin

3 Terms of Reference and Scope

3.1 The Terms of Reference for the Workgroup can be found in Annex 2.

3.2 The Terms of Reference for the Workgroup were reviewed and the following was noted:

- Point 5.c – It was agreed that the Workgroup needed to obtain a legal opinion on the Regulation and the legal opinion should include whether reasonable endeavours by National Grid are sufficient to comply.

- Point 5.d - One Workgroup member challenged why the cap should be set at €2.50/MWh and not another value in the middle ground. Another Workgroup member asked whether ACER's April 2014 opinion to remove power based caps on G charges was likely to be adopted by the Commission. Ofgem confirmed that in their view this was unlikely as 18 months had now passed.[1] If ACER's position at that time would be reflected in the Regulation, there would be no cap on power based G-charges across all the Member States.

3.3 A Workgroup member stated that the recent CMP227 decision[2] implied that there should be no consideration of this CMP251 modification proposal as Ofgem had stated that it was unclear how Generator charges would evolve in Europe, and therefore any changes now may be required to be undone in the future. The concern was that by implementing a change in this area a precedent would be set ahead of possible future change in Europe. Ofgem confirmed that this CMP251 modification applied to the present situation and therefore should be considered.

3.4 There was a brief discussion on other ways the objectives of the modification could be met but it was agreed that the scope of the modification does not permit alternatives suggesting an increase in the size of the error margin because the CMP251 defect is identified as the error margin itself.

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[1] By way of background, a report was published by ACER, outlining its conclusions on European tariff structure harmonisation, which can be found at: http://www.acer.europa.eu/Events/2nd-ACER-workshop-on-electricity-transmission-tariff-harmonisation/Documents/CEPA%20Scoping%20Draft%20Final%20Report.pdf. A further ACER report has since been published in December 2015 re-confirming its position and requesting the Commission to reflect this in an update to the Regulation. This report can be found here: http://www.acer.europa.eu/Electricity/FG_and_network_codes/Documents/Scoping%20conclusions%20for%20harmonised%20Transmission%20Tariff%20Structures%20in%20Electricity.pdf

[2] https://www.ofgem.gov.uk/sites/default/files/docs/2015/09/cmp227_d_0.pdf

4 Workgroup Discussion

4.1 The Workgroup discussed the benefits of CMP251 as advocated by the Proposer:

(a) Certainty of Regulation compliance:

(i) Whilst the current ex ante methodology uses reasonable endeavours to comply with European Commission Regulation 838/2010 there remains a real risk that average annual transmission charges paid by Generators in GB may exceed €2.50/MWh in some circumstances. The legal opinion states that the proposal "…*has the inherent advantage of using established figures (as opposed to forecast figures/the Error Margin) and thereby achieving a more certain and precise alignment with the G Charge Guidelines (albeit…we are not of the view that this precise ex-post alignment is essential as a pre-requisite for legal compliance with the G Charge Guidelines*)"[3]. Therefore in the view of some Workgroup members it achieves a more certain and precise alignment with the Regulation 838/2010. as reflected in the legal text

(ii) Other Workgroup members highlighted that the legal opinion requested by the Workgroup noted that the existing ex ante methodology is compliant with Regulation 838/2010 - "…..*we are of the view that there is a robust argument that the Current Approach ensures compliance with the purpose of the Guidelines Regulation and therefore is not vulnerable to legal challenge by dint of taking using ex ante calculations*"[4] In the opinion of these Workgroup members there is therefore no uncertainty of Regulation compliance.

(b) Minimising impact on the principles underpinning TNUoS tariffs:

(i) The sole purpose of CMP224 was to manage compliance with the European Commission Regulation 838/2010. The result of CMP224 was to alter the charges that would otherwise have resulted from the application of the charging methodology. The underlying principles of the charging methodology, including the default split of revenue between Generators and Suppliers, were not affected by CMP224. The Proposer believes therefore, that the application of a cap distorts the principles of the charging methodology. By removing the error margin, the proposed CMP251 solution will therefore also minimise the distortive effect on the underlying TNUoS principles.

(ii) Some Workgroup members expressed the view that an ex ante approach enables efficient trading and provides certainty to market participants. As outlined in CUSC Section 14.14.8 the charges also have the objective to "inform existing and potential new entrants with accurate and stable cost messages", and it could be argued it is difficult to see how introducing (with CMP251) an ex post reconciliation of exchange rate risk stabilises charges. It was noted that the Workgroup for CMP224 considered including exchange rate risk into the ex ante methodology and stated that: "*in relation to the €/£ exchange rate, the Workgroup viewed this as being driven by external factors and impractical for electricity industry participants to forecast with any degree of certainty*"[5].

(iii) It was expressed by the Proposer that removing the error margin itself would improve predictability for market participants since the actual level of the error margin is subject to change (in line with standard tariff notification timescales and as may be discussed in advance at the Transmission Charging Methodology Forum), which can add

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[3] Page 37 of CMP251 Workgroup Consultation Q6, Para 3.

[4] Page 36 of CMP251 Workgroup Consultation Q1, Para 5.

[5] Paragraph 4.46, CMP224 Final Modification Report http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP224/

uncertainty to market participants. Other members of the Workgroup considered that removal of the error margin would indeed improve predictability for market participants, but it is the ex post reconciliation that creates new uncertainty and less predictability.

(iv) CMP251 introduces an exchange rate risk into the reconciliation charges as the current ex ante approach does not take into account €/£ currency fluctuations (and does not have a reconciliation process). The consequence of introducing an exchange rate risk would be that as it is viewed to be "*impractical for electricity industry participants to forecast with any degree of certainty*"[6], and some Workgroup members believed that market participants (both Generators and Suppliers) will begin to introduce risk margins into end customer tariffs to hedge against adverse €/£ currency movements. Using the Office of Budget Responsibility (OBR) €/£ exchange rate data, analysis was performed by the Workgroup which indicated that the highest expected variance in the €/£ exchange rates (using data from the last 5 years) would be + or -14%[7]. Assuming recently observed annual €/£ exchange rate changes, this could result in revenue movements of as much as £120m[8] between Generators and Suppliers compared to expectations over 2 years previously. Whilst this may lead to consequential transmission tariff uncertainty, clearly uncertainty will continuously reduce both prior to the setting of TNUoS tariffs, and during the relevant Charging Year, as market participants have visibility of movements in the €/£ exchange rate. For instance, the 14% variance quoted above in respect of the 2015/16 Charging Year reduces to a 1% variance when compared to the revised OBR forecast published prior to the 2015/16 Charging Year.[9] However, that having been said, it was noted by some Workgroup members that Generators may well have traded their output forward monthly, quarterly, seasonally, annually ahead[10] such that they would have had to factor in the €/£ exchange rate at the time they priced those trades in the market. It is noted though that whilst Parties will have increasing certainty over the required revenue movement, the size of the revenue movement itself is not affected since the TNUoS methodology fixes the exchange rate using the OBR spring forecast in the previous year.

(v) It was noted by some Workgroup members that options may be available to market participants which would offer protection against the €/£ exchange rate movements. However, other Workgroup members noted that options to hedge the €/£ exchange rate risk would come at an additional cost to those parties. Large established market participants will be better able to manage the €/£ exchange rate risk as they are likely to already have exchange rate expertise. However, this is unlikely to be the case for smaller market participants. Therefore, exposing market participants to the €/£ exchange rate risk through the TNUoS charging arrangements is likely to put smaller market participants at a competitive disadvantage. To some degree, this may unduly distort competition in electricity generation and supply.

(c) Minimising the required transfer of costs from generators to consumers:

(i) By including an error margin (which is currently set at 8.2% for the 2016/17 Charging Year) Suppliers are collectively contributing ~£40m more than if no error margin

[6] Paragraph 4.46, CMP224 Final Modification Report

[7] For Charging Year 2015/16, the OBR forecast published in March 2014 was €1.22, at one point during the year the exchange rate was up at €1.39.

[8] See spreadsheet analysis

[9] For Charging Year 2015/16, the OBR forecast published in March 2015 was €1.37, at one point during the year the exchange rate was up at €1.39 – a 1% variance.

[10] Which, for example, facilitates Suppliers being able to offer consumers fixed price contracts.

was used and the G:D split was set using the top of the €0-2.5/MWh range defined in Regulation 838/2010 Part B. However, removing this cost from Suppliers may not necessarily lead to a saving to be made by consumers, as it could be argued that this is simply a movement of costs from Suppliers to Generators. The Proposer believes that just as there is a risk that not all of the reduction in generation TNUoS charges resulting from CMP224 is passed through to consumers via lower wholesale prices, similarly it is not certain that all of the c. £40m transfer back to generation will be passed through to consumers via higher wholesale prices. The Proposer stated that to the extent that generators are not able to pass through these movements in TNUoS costs, the CMP 251 proposal will be beneficial to consumers by reducing the windfalls being received by some generators under the current methodology.

(ii) Some Workgroup members were mindful that the Provisional Findings of the CMA and Ofgem's Wholesale Market Indicators Report (2015) confirm the absence of temporal market power in the GB generation market and conclude that the market is competitive and that there is no evidence that TNUoS cost reductions for generators are not being passed on to consumers via the wholesale power price. Therefore there is no evidence that generators in GB are making any windfall gains. Conversely, it is highly doubtful whether TNUoS cost increases for generators would not be recovered from consumers (where the generator is economic). But in any case, generators that are unable to recover their operating costs will eventually exit the market; e.g. Fiddlers Ferry and Rugeley Power Stations. An inability for economic entities to pass through the costs they incur is detrimental to competition and security of supply and ultimately consumers; it cannot be considered a benefit.

(iii) Some Workgroup members noted that the Regulation 838/2010 Part B defines a range of €0-2.5/MWh, and therefore proposed referencing another number (such as the 'mid-point') within the range i.e. €1.25/MWh, rather than the €2.5/MWh cap. As the EU Regulation defines a range rather €2.50/MWh this means that there is no legal requirement to minimise the required transfer of costs from Generators to Suppliers although there is a legal requirement not to affect cross-border trade.

(iv) Some Workgroup members considered that the Proposal could also mean higher costs for consumers as a result of interest charges where National Grid would be financing the cost of any under-recovery that results from the proposed reconciliation of Generators in Charging Year+1, and Suppliers in Charging Year+2. Other Workgroup members noted that under recovery effectively delays charges. They therefore consider that whether or not consumers, or any other Party, incur higher overall costs will depend on the net effect of the interest applied to over and under recovery and the change in interest payments/earnings that would accrue to the Party as a result of charges being delayed. For example, if we assume National Grid under recovers from demand network users by £100million in a Charging Year 1, and recovers this in year 2 with an interest rate of 2.5% applied to the under recovery, then in Charging Year 2 National Grid will recover £102.5 million. Demand network users pay £2.5million more in charges (£102.5 million instead of £100 million) but they also earn or avoid paying interest on the £100million under recovery. If, network users earn or avoid paying 4% interest on the £100million, ie £4million, then the net impact on them is a benefit of £1.5million. If that interest rate is 2.5%, then they are cost neutral. If it is 2% then there's a net cost of £0.5m.

(d) Provide predictability by providing a fixed cap for Generators:

(i) Some Workgroup members noted that greater certainty for Generators is achieved as they will know that after reconciliation their charges will be at the cap. By monitoring the €/£ exchange rate variations both prior to and during the Charging Year Generators should be in a position to predict the likely reconciled charge and reflect this in the price of power sold.

(ii) However, other Workgroup members noted the counter arguments set out in paragraph (b) (v) above. In addition, where the cost of hedging the £/€ risk is prohibitive, Generators can be exposed to gains and losses on forward wholesale power sales depending on how the exchange rate fluctuates. This is because Generators cannot predict future exchange rate fluctuations. This would give rise to the introduction by Generators of a £/€ TNUoS risk premia.

(iii) Overall the removal of the current ex ante error margin and the application of an ex post reconciliation of Generator TNUoS charges should, in the view of some Workgroup members, also reduce year to year variability of the unreconciled generator TNUoS charges set at the start of each year. This is because the proposal will have in the previous charging years recovered average generator charges at the 'right' level (i.e. typically at the cap).

(iv) However, some Workgroup members feel that there may already be undue competitive disadvantage and setting average Generators charges at €2.50/MWh may put GB generation at a further undue competitive disadvantage relative to their continental competitors and affect cross-border trade. This may be detrimental to the Internal Market as well as to (i) effective competition in GB, (ii) GB security of supply and (iii) achieving the UK's legally binding environmental targets.

(v) "One member of the working group did not believe that GB generation was at a competitive disadvantage relative to their continental competitors and considered it is not appropriate to compare one component of GB transmission charges without considering the wider commercial regime. For instance, generators in GB receive firm transmission rights and also benefit from ancillary service payments. When it is considered that approximately £500m is recovered through TNUoS from generation, and that approximately £1bn is made in payments to generation through BSUoS (to which demand contributes 50%), it could be argued that the net position is broadly neutral. The working group member also challenged whether TNUoS affects cross border trade since TNUoS is a fixed cost and not a short run marginal cost. However it was accepted that setting the average G charge at €2.5/MWh (relative to a lower level due to the error margin) will result in a higher proportion of transmission charges being paid by generation, and as a fixed cost this may marginally affect future investment decisions where there are alternative options on the continental mainland."

(vi) Some Workgroup members felt that introducing an ex post reconciliation and adding the €/£ exchange rate risk does not increase predictability of TNUoS costs for Generators. Conversely an ex ante methodology maximises predictability of TNUoS costs for Generators. However, the Proposer believes that the use of an ex ante based error margin increases unpredictability due to unforeseen changes in the level of the error margin. This risk is effectively 'doubled up' as it applies equally, but in opposite directions, to both Generators and Suppliers.

(e) Predictability to Suppliers:

(i) The Proposer noted that with the proposal Suppliers will have certainty that the G:D split will be set so that average TNUoS charges will be set to recover the cap set by the Regulation without the unpredictability and risk associated with unanticipated changes to any error margin. This risk, according to the Proposer, will therefore be removed and the impact on any over/under recovery position of National Grid will be known with increasing certainty through the relevant Charging Year and any reconciliation will not take effect until the second year after the relevant Charging Year providing predictability to Suppliers of the impact on future year TNUoS tariffs.

(ii) Other Workgroup members commented that introducing an ex post reconciliation and adding the €/£ exchange rate risk does not increase predictability for Suppliers. Managing the €/£ exchange rate risk comes at a cost (please see paragraph. (b) (v) above). Conversely an ex ante methodology maximises predictability for Suppliers.

(f) Removes the risk of changes in the error margin:

(i) Changes to the error margin are made at the discretion of National Grid and do not require any notice (other than as provided for in the TNUoS tariff notification). The Proposer believes that the use of an error margin increases unpredictability due to unforeseen changes in the level of the error margin. This risk is effectively 'doubled up' as it applies equally, but in opposite directions, to both Generators and Suppliers.

(ii) Other members of the Workgroup noted that changes to the error margin are evidence based on the basis of historical forecast errors. Removing the error margin with

CMP251 just exchanges one form of risk for another, however, in the current ex ante methodology, this is known in advance by Generators and Suppliers, whereas in the CMP251 ex post methodology the reconciliation amount is not known in advance, meaning both types of parties have to factor in a risk premium for this uncertainty.

4.2 The Workgroup discussed other issues associated with the modification:

(a) One of the intentions of Regulation 838/2010 was to not undermine the Internal Market. For this reason average charges for access to the transmission network by Generators in Member States were to be kept within a range which helps to ensure that the benefits of harmonisation are realised and it was on this basis that the €0-2.5/MWh for GB was set. In the opinion of some Workgroup members this intention lends itself more closely to an ex ante methodology.

(b) The Proposal introduces a new reconciliation process which is more complicated than the existing ex ante process.

(c) In the view of a Workgroup member the CMP251 reconciliation process could improve cost reflectivity by reflecting actual £/€ exchange rate movements, however any gain in cost reflectivity, could be affected by market share changes that result in the intervening two separate charging years. Other Workgroup members stated that setting TNUoS tariffs to ensure that Generators pay on average €2.50/MWh exactly could not be considered more cost reflective. This is because the EC Regulation proscribes an average charge range of €0/MWh - €2.50/MWh. Any average charge within this range could be considered cost reflective. In any case, setting average Generator TNUoS charges at exactly €2.50/MWh wouldn't provide useful cost reflective signals for Generators to change their behaviour in any meaningful way.

4.3 The Workgroup discussed the actual effect the Modification would have on market participants. It was noted that for balanced vertically integrated[11] players, this Modification should (in theory) have little or no effect as costs are transferred from the generation to the retail business or vice versa. However, those market participants that are not vertically integrated would be exposed to gains or losses, particularly where only short notice periods are provided.

The Accrual Concept and CMP251

Some Workgroup members felt that by introducing the changes suggested in CMP251, it was important to highlight the impact resulting from the Accounting Accrual Concept and the introduction of financial uncertainty into the accounts. A Workgroup member provided further clarification below on the potential impact.

CMP251 proposes to introduce a new charging element to TNUoS which would involve reconciling charges to Generators at some point after the end of the Charging Year ('t', ending 31st March). The stated aim of the Proposal is to ensure that the average amount recovered from Generators in that Charging Year (t) is equal to €2.50/MWh in compliance with Regulation 838/2010. The reconciliation amount payable (or receivable) by Generators in the following Charging Year (t+1) would be clearly identified as an adjustment to the TNUoS charges due for the prior Charging Year (t), and would be expressed through a change in the TNUoS tariffs for that prior Charging Year (t) and applied to the Generator volumes delivered in that prior Charging Year (t). Therefore, under the accrual concept, any Generator reconciliation amounts would have to be recognised in the year to which they relate i.e. the prior Charging Year (t). To the extent that Generators are reasonably certain that such a

[11] As in their own generation output balancing their supply needs.

reconciliation amount would arise (through National Grid forecasts/updates or internal calculation using publicly available data, such as the €/£ exchange rate) and even although the final reconciliation process may not yet have taken place and the appropriate payments/receipts not yet exchanged in the next Charging Year (t+1), Generators should recognise the anticipated amount in their financial statements for the prior Charging Year (t).

In the case of Suppliers, CMP251 proposes that any consequential adjustment would be carried forward as an over/under recovery of Allowed Revenues into future Charging Years' TNUoS charges. It is therefore the Supplier TNUoS tariffs in those future Charging Year (t+2), which will be applied to the Supplier volumes in those future Charging Years (t+2), which will be adjusted. In this case, the accruals concept will not apply as the adjustment will not be applied to Supplier volumes delivered in the prior Charging Year (t).

The Accrual Concept

The accrual concept is the most fundamental principle of accounting which requires recording revenues when they are earned and not when they are received in cash, and recording expenses when they are incurred and not when they are paid.

The accrual concept of accounting requires that income and expense must be recognized in the accounting periods to which they relate rather than on a cash basis. Under the Accrual basis of accounting, income must be recorded in the accounting period in which it is earned. Therefore, accrued income must be recognized in the accounting period in which it arises rather than in the subsequent period in which it will be received. Expenses, on the other hand, must be recorded in the accounting period in which they are incurred. Therefore, accrued expense must be recognized in the accounting period in which it occurs rather than in the following period in which it will be paid. The accrual basis of accounting ensures that expenses are "matched" with the revenue earned in an accounting period. Accruals concept is therefore very similar to the matching principle.

Generally Accepted Accounting Practice (GAAP) allows preparation of financial statements on an accrual basis only (and not on a cash basis). Application of the accrual concept results in accurate reporting of net income, assets, liabilities and retained earnings which improves analysis of the company's financial performance and financial position over different periods. In the UK, GAAP on accruals is contained in Financial Reporting Standard 18 (FRS 18) – Accounting Policies.

European Regulation

4.4 The Workgroup agreed to acquire legal opinion on the interpretation of EU Regulation 838/2010 Part B. The EU Regulation can be found in Annex 3. The Workgroup identified the key questions as follows:

(a) Do the 'Guidelines for A Common Regulatory Approach to Transmission Charging' set out in Part B of 838/2010 apply to:

(i) Calendar years only

(ii) Charging years as applicable in the regulatory arrangements for each member state only i.e. regulatory years (Apr-Mar) for GB

(iii) Both a. and b. (if a. and b. are different)

(iv) Either a. or b. (if a. and b. are different)

(v) It is inconclusive. In which case, would it equally be defensible or consistent with the legal and regulatory scheme for a member state to put in place arrangements to comply with the one (a. or b.) it deemed most appropriate.

(b) Legal advice on the above would facilitate working group discussions on the timing of any adjustment.

(c) Does the regulation specify payment terms between produced/generators and National Grid?

(d) Would removing the error margin and introducing reconciliation after the year be better, worse or neutral in terms of compliance with the regulation as compared to the baseline?

(e) Would removing the error margin and introducing an adjustment within year be better, worse or neutral in terms of compliance with the regulation as compared to the baseline?

(f) Is there any time limitation for any correction in respect of either a within year adjustment or after the year reconciliation taking place? If so which time limitation is preferable e.g. 30 days; 3 months; 6 months; 12 months?

(g) The current arrangement sets charges based on forecast. They include an error margin to mitigate the risk of exceeding an average charge of €2.50 per MWh due to forecast error. However, this risk is not mitigated entirely and charges could still exceed €2.50 per MWh.

(i) If this happens are charges in breach of the regulation?

(ii) If so, does action need to be taken to comply with the regulation, e.g. by refunding part of generation charges?

(iii) If action has to be taken, should it be within year adjustment or after the year reconciliation or either?

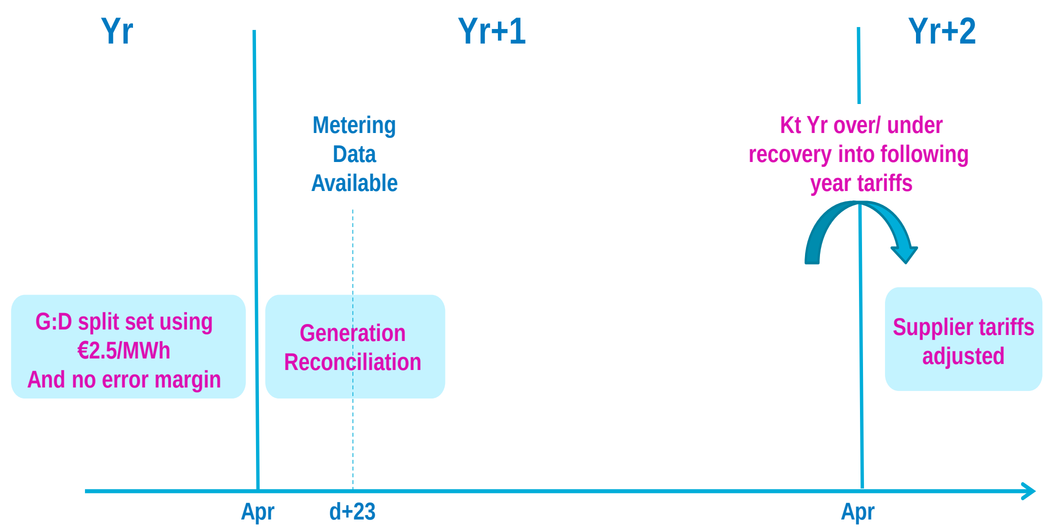
4.5 The legal firm Addleshaw Goddard were commissioned by National Grid to provide an opinion for the Workgroup on the above and this can be found in Annex 4. In summary, the legal opinion suggests either an ex ante or an ex post approach is justifiable under the terms of the Regulation and that Member States have a high degree of latitude to implement the most appropriate methodology that matches the relevant commercial regime. The legal opinion discusses the pros and cons of both methods, and concludes that both the Proposer's approach and the current approach are viable. It is essentially up to the Workgroup to outline which approach offers the best solution.

4.6 The legal opinion also confirmed that in an ex ante approach there is no breach of the Regulation if appropriate measures have been taken to conform with the Regulation, and in the view of Addleshaw Goddard, the current ex ante method is robust. However, the legal opinion also stated that the modification has the inherent advantage of using established figures (as opposed to forecast figures/the Error Margin) to calculate average Generation Charges, thereby achieving a more certain and precise alignment with the Generation Charge Guidelines. The legal opinion states "*the ex-post mechanism through which the BG Proposal [CMP251] calculates average G Charges has the inherent advantage of using established figures (as opposed to forecast figures/the Error Margin) and thereby achieving a more certain and precise alignment with the G Charge Guidelines (albeit…we are not of the view that this precise ex-post alignment is essential as a pre-requisite for legal compliance with the G Charge Guidelines)*."[12]

4.7 Although the Workgroup questions had been broadly answered by the legal opinion response, one group member requested the legal opinion be restructured to respond directly to the questions the Workgroup had proposed to ensure that nothing had been missed and it was agreed this would be helpful. The restructured response can also be found in Annex 4.

Under or Over Recovery Mechanism

4.8 The Modification Proposal advocates the following reconciliation mechanism where Generators would be reconciled in Charging Year t+1 and Suppliers in Charging Year t+2 for any under or over recovery in the initial Charging Year t:



[12] Page 37 of CMP251 Workgroup Consultation Q6, Para 3.

4.9 The above can be achieved through adjustment of the generation and demand residual TNUoS tariffs. It was noted that the Original Proposal leads to a reconciliation timing delay between Generators and Suppliers.

Network users pay interest on under-recoveries.

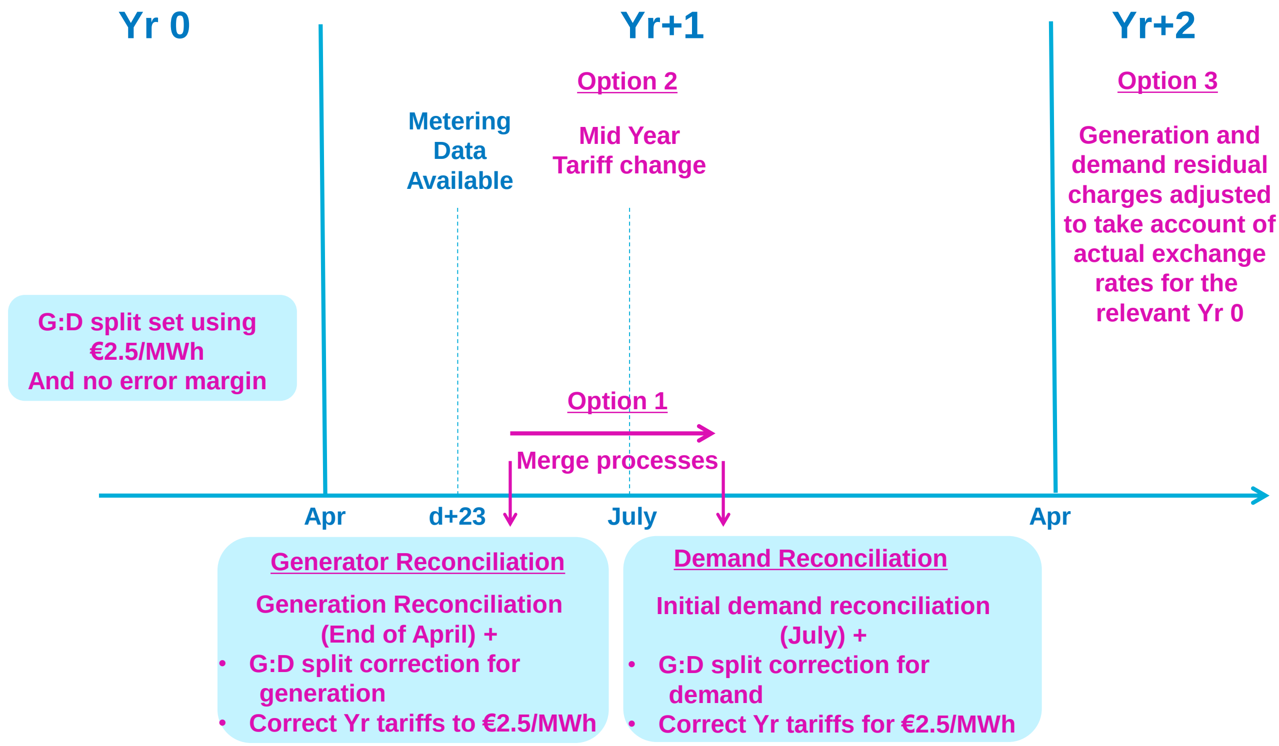
Example: Generators pay more than the 2.5 euro cap, National Grid pay £80m back to generators in year t+1. This becomes an under recovery on k, leading to increase in year t+2 tariffs and interest paid to National Grid on this money they have funded. £80m becomes £ 84.2m increase in Allowed Revenue as % 2% + Bank of England base rate interest is charged by National Grid for each of the relevant 2-years (Yr and Yr+1).

National Grid pays interest on over-recoveries.

Example: Generators pay under the 2.5 euro cap, National Grid receives £80m from generators in year t+1. This becomes an over recovery on k, leading to decrease in year t+2 tariffs with interest paid by National Grid on this money they held. £80m becomes £84.2m decrease in Allowed Revenue as 2% + Bank of England base rate interest is charged to National Grid on a 2-year recovery.

Note that as set out in 4.1 c (iv), some Workgroup members consider that whether or not any Generator or Supplier incurs higher overall costs is dependent on the net effect of the change in TNUoS charges and the change in interest payments that would accrue to the Generator or Supplier as a result of charges being delayed or brought forward.

4.10 Three other possible *simultaneous* reconciliation options (avoiding the potential additional cost of financing any under recovery) in the event an ex post approach was adopted could also be implemented using existing processes and they are shown below:



4.11 It should be noted that with a mid-year[13] (in t+1) tariff change (Option 2 shown above), all new information available to National Grid at that time (such as changes to demand, generation TEC levels, OFTO income etc.) would be included, and not just an updated €/£ exchange rate position.

4.12 In the event an ex post process was adopted, National Grid confirmed that a good enough set of data for Generator reconciliation is available at D+23 as per the existing standard metering settlement timescales. Presently a generation reconciliation process is carried out at the end of April (in t+1) to take account of power station demand and generation in negative TNUoS charging zones in the preceding Charging Year t. Initial demand reconciliation is also carried out in July (t+1) to take account of the latest metering data for the preceding Charging Year t.

4.13 Discussion centred on the impacts of the options with the following points noted:

- The Original creates a cost of financing for National Grid between the payment made to Generator in spring t+1 and the recovery of the amount paid to Generators from Suppliers via the Kt into the following Charging Year t+2. The Proposer noted that the Regulation only refers to Generation charges that must be in the range €0-2.5/MWh for the Charging Year t in question and therefore there was no need to include Suppliers in the reconciliation in spring t+1. However, it was noted that further consideration is required as to how the payments to or from Generators in Charging Year t+1 for the initial Charging Year t are to be accounted for in terms of then calculating the average annual TNUoS charges paid by Generators in Charging Year t+1.

- The issue with Option 1 is that Generation reconciliation is merged with the Supplier reconciliation and so resourcing this process concurrently could become an issue both for National Grid and industry.

- Option 2 would use the existing mid-year tariff change mechanism, which was last utilised in 2010/11. There was little appetite within the Workgroup for pursuing this option as it would introduce uncertainty of Generators' and Suppliers' TNUoS costs. This could be detrimental to competition in the wholesale and retail market.

- Option 3 allows forreconciliation of both generation and supplier positions through simultaneous generation and demand residual tariff adjustment, avoiding financing costs, and without the possible resourcing issues associated with Option 1 as it would just be an additional component of the annual tariff setting process. The downside is that it is a full 2 years after the relevant year in question, and therefore physical market participant positions may have changed in the intervening time leading to reconciliation amounts being transferred to incorrect parties. Any theoretical gains in ex post cost reflectivity could be lost with this delay due to participant changes in market shares.

Analysis of materiality and potential cost of financing

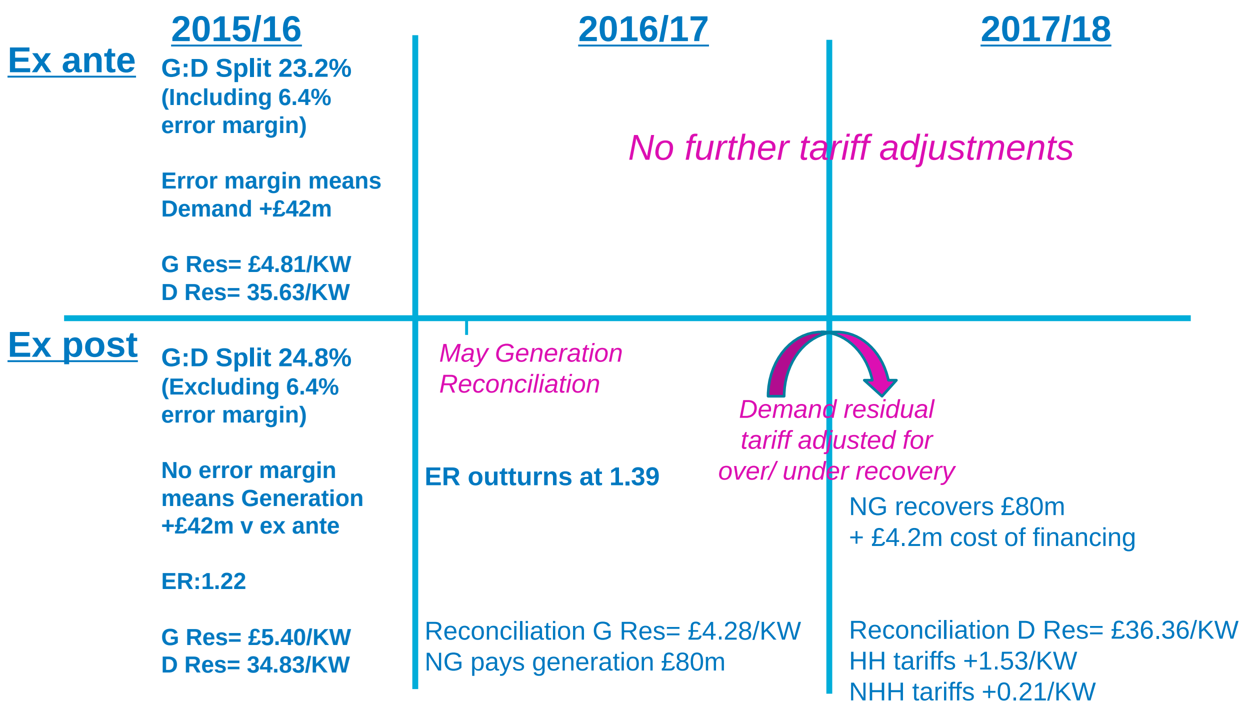
[13] Note 'mid-year' does not mean the mid-point in the Charging Year – a change could occur on, for example, the 2nd April or 30th March or anytime in between.

4.14 Parameters for Charging Year 2015/16 and 2016/17 were used (for illustrative purposes only) to perform an analysis of the materiality of the proposed CMP251 ex post methodology in comparison to the existing ex ante methodology. The analysis is shown in Annex 5.

4.15 When the error margin included in the ex ante calculation is removed, it has the effect of changing the G:D split and transfers approximately £40m from demand to generation. The ex post approach also introduces a €/ exchange rate risk to the reconciliation. The following diagrams illustrate how these movements would play out under the CMP251 original proposal versus the existing ex ante approach.

Impact Analysis had CMP251 been implemented for 2015/16

- Analysis of exchange rate risk only



*For simplicity, the cost of financing has not been included in the reconciliation demand residual tariffs

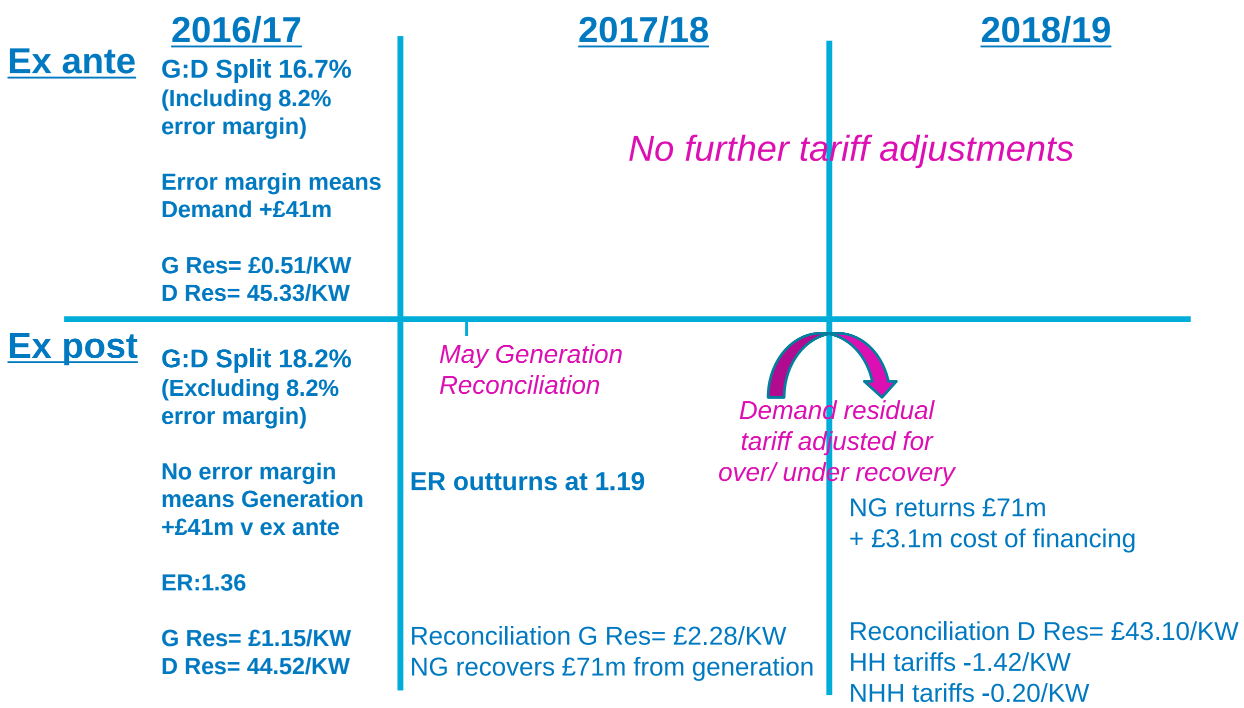
4.16 In the above diagram, using actual data, had hypothetically CMP251 been implemented for Charging Year 2015/16, the G:D split would have been 24.8:75.2 with a ex post approach (rather than 23.2:76.8 in the ex ante approach). This would mean that the starting TNUoS tariffs from 1st April 2015 would have been higher for generation and generation would have paid about £40m more during the Charging Year 2015/16. If CMP251 had been in place in 2015/16 then there would have been no error margin. During the course of that year, the exchange rate moved from €1.22 to €1.39 and this would lead, under the CMP251 proposal, to a reconciliation of generator charges in the May of the following Charging Year t+1 (2016/17). Thus, for Charging Year 2015/16 this would (hypothetically) have led to National Grid paying generators £80m around May 2016. According to the Transmission Licence, National Grid would be entitled to levy an under-recovery rate of interest associated with the

£80M payment made by them to Generators in t+1 (2016/17). This would amount to £4.2m[14] and would be recovered from Suppliers in Charging Year t+2 (2017/18) along with the £80M under recovery from t (2015/16). Demand TNUoS tariffs for Charging Year t+2 (2017/18) would (based on the £84.2M figure) subsequently be increased by £1.53/KW for HH and an average of £0.21/KW for NHH demand as a result.

4.17 For Charging Year 2016/17 ('x'), two scenarios have been generated to illustrate the impact of the €/£ exchange rate risk on transmission tariffs. Scenario A shows the effect of a similar movement in exchange rates to that experienced in 2015/16, but in the opposite direction. Scenario B illustrates a continuing increase in the strength of the pound against the Euro.

Impact Analysis had CMP251 been implemented for 2016/17

- Scenario A: ER moves down by as much as 2015/16



*For simplicity, the cost of financing has not been included in the reconciliation demand residual tariffs

4.18 Scenario A again shows that the CMP251 ex post G:D split methodology without the error margin would be higher than the current ex ante approach. During the Charging Year x (2016/17), the

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14

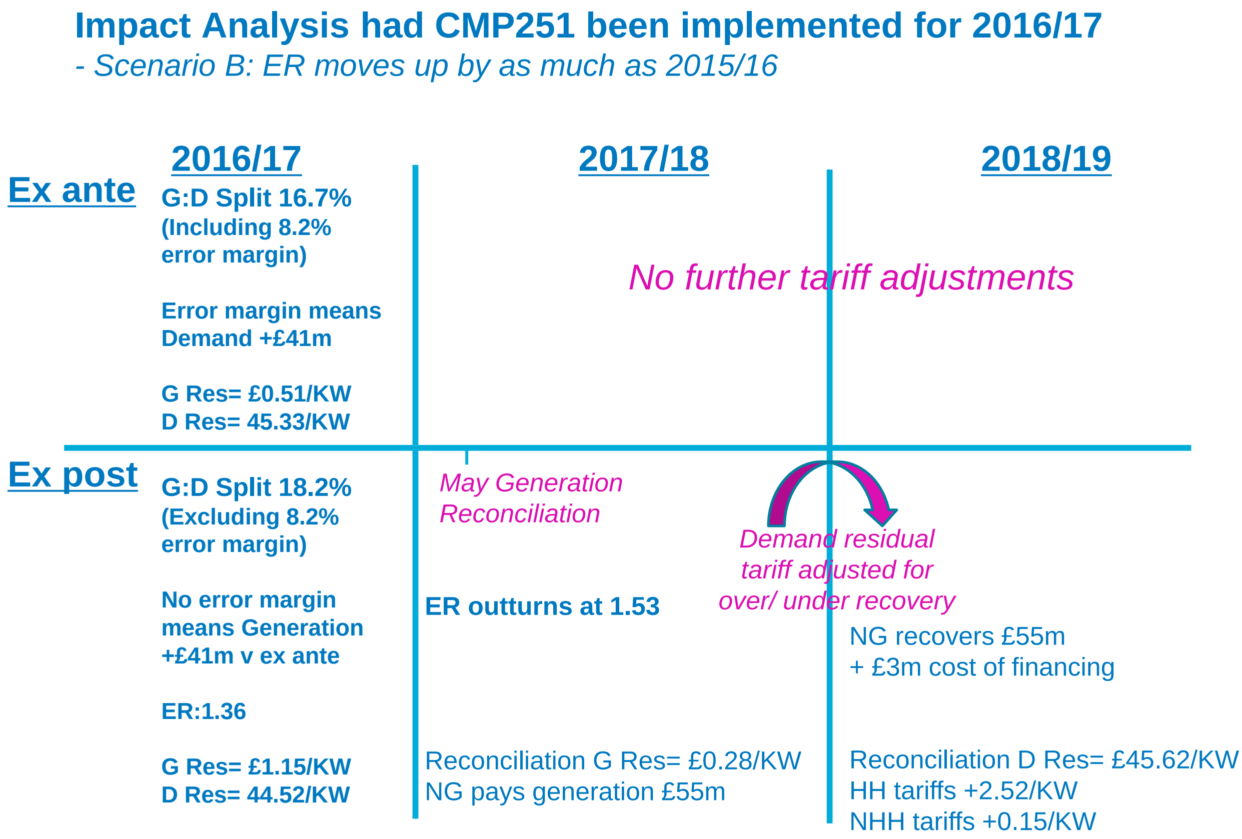
Part E: Calculation of the correction term (K_t)

3A.14 For the purposes of the Principal Formula, subject to paragraph 3A.15 and 3A.16, K_t is derived in accordance with the following formula:

$$K_t = (TNR_{t-2} - TO_{t-2}) \times \left(1 + \frac{I_{t-2} + PR_t}{100}\right) \times \left(1 + \frac{I_{t-1} + 2}{100}\right)$$

Interest rate for 2015/16 was 0.5%, 2016/17 0.65% and for 2017/18 0.95% as per the November 2015 OBR forecast http://budgetresponsibility.org.uk/efo/economic-and-fiscal-outlook-november-2015/ chart 3.8 on page 45 exchange rate could move from €1.36 to €1.19. This would require (hypothetically) National Grid to recover (£71m+£+3.1m)£74.1m1 from Generators which would then be passed on to Suppliers in Charging Year x+2 (2018/19).

4.19 Some Workgroup members expressed the views that it is unclear whether the over recovery paid to Suppliers would be subsequently passed on to consumers considering the competition concerns set out in the initial CMA Energy Market Investigation. In this Scenario there would be no cost of financing (of the £71M) to National Grid, but a lost opportunity cost to Generators paying £71M which will be detrimental to future generation investments. It was noted that this cost is likely to be higher for Generators than National Grid's cost of financing as Generators have an appreciably higher cost of capital than National Grid. Some Workgroup members did not consider that the proposal would be detrimental to future generation investment since such investments should be made on the basis of a long term view of costs and revenues. Since CMP 251 reconciliations can be assumed to be symmetrical, over the long term they would not expect the OBR forecast to be biased in any particular direction.



*For simplicity, the cost of financing has not been included in the reconciliation demand residual tariffs

4.20 In Scenario B, the same situation as Charging Year 2015/16 plays out for Charging Year x (2016/17) with the pound strengthening relative to the Euro. National Grid would (hypothetically) pay generation £55m in the May 2017 reconciliation and recover £58m, including the National Grid cost of finance, from Suppliers in Charging Year x+2 (2018/19).

4.21 National Grid's cost of financing would be avoided for alternative reconciliation Options 1, 2 and 3 described above.

4.22 From National Grid's perspective, a significant feature is the effect that the additional CMP251 €/£ exchange rate uncertainty would have on the bandwidths determining the interest rate to be applied for over or under recoveries. The Transmission Licence implements penal interest rate charges[15] for National Grid where under or over recovery exceeds 5.5% of the Allowed Revenue. In Charging Year 2016/17 the 5.5% of the Allowed Revenue is £149m and therefore an ex post reconciliation process would introduce a significant new risk for National Grid, and one which the existing bandwidths set out in their Transmission Licence were not designed to accommodate.

Comparison to other Member State Approaches to EU Regulation 838/2010

4.23 The Workgroup considered it may be helpful to consider how other Member States in Europe go about implementing Regulation 838/2010 Part B.

4.24 It was noted that eight Member States apply transmission charges to Generation, and most of those use energy-based (MWh) charges rather than power-based (MW) charges. Only Sweden, the UK and Ireland use power-based charges. Sweden also uses an ex ante methodology, but without an error margin, and a detailed description of the Swedish methodology is provided in Annex 6 including theoretical analysis of how this methodology would transpose to GB charges. In summary, the Swedish method uses an assumed utilisation rate of 5000 hours for each contracted MW of generator without the use of an error margin. It was noted that this equated to an annual load factor for Swedish generation of 57% whereas GB generation had widely differing annual load factors.

4.25 The Workgroup did not consider that the Swedish approach merited further consideration with the existing ex ante GB approach being preferable to the Swedish ex ante approach as the assumed 5000 hour utilisation rate may be incorrect for the mix of generation plant in GB.

4.26 The Workgroup considered it would be interesting to understand how many EU countries are adjusting their Generation transmission charges with reference to EU Regulation 838/2010 Part B.

Further Workgroup discussion following the CMP261 legal opinion.

4.27 In the light of the CMP261 legal opinion the Panel felt that the CMP251 Workgroup needed to review whether the legal opinion for CMP261 impacted on the solutions suggested for CMP251. The difference between the legal advice for CMP261 and CMP251 is because it recognises the potential of a material breach. The CMP261 legal opinion can be found in Annex 8 for your reference.

4.28 In the view of a Workgroup member the legal opinion obtained for CMP261 confirms that it would be prudent to look at an enduring solution, however, a further Workgroup member felt that because the defect in the CMP251 Proposal only focuses on the error margin, CMP251's scope is too narrow to consider all potential enduring solutions. Another Workgroup member asked why we could not ask further questions on the WACM's. Currently the WACMs are one and two ways (either Generator reconciliation or a Supplier and Generation reconciliation), so it would be prudent to ask if further buffers should be added into the solutions to CMP251, for example, a materiality calculation ex post to rectify any potential breaches going forward. For some Workgroup members this then raised the question of how the materiality can be determined for other parties by the CMP251 Workgroup. For one party one million pounds might be material but for another party this may be viewed as an immaterial value. A legal question is in law what is material?

4.29 The proposer felt that the materiality calculator reduces certainty of a mechanism which CMP251 seeks to increase the certainty of. CMP251 in its core essence seeks to put all parties on a level

[15] In the case of under-recoveries, only Bank of England interest rate would apply, and in the case of over-recoveries, 4% + Bank of England base rate would be returned

playing field by removing the error margin and even if a materiality calculator is introduced it could still mean that a party disagrees with the materiality and raises a further modification to claim a rebate anyway.

4.30 A Workgroup member felt that the best way to deal with an enduring solution would be following the Authority decision on CMP261, that, if the decision letter identifies the requirement of an error margin then industry would need to reconvene to review the potential of a materiality calculator or any further solutions.

4.31 No Workgroup members proposed any new WACMs or changes to any previously raised WACMs based on the CMP261 legal opinion. As a result the Workgroup did not re-vote and the previous voting and commentary stands the same as recorded in the other sections of this report.

5 Impact and Assessment

Impact on the CUSC

5.1 Changes to Section 14

Impact on Greenhouse Gas Emissions

5.2 None identified.

Impact on Core Industry Documents

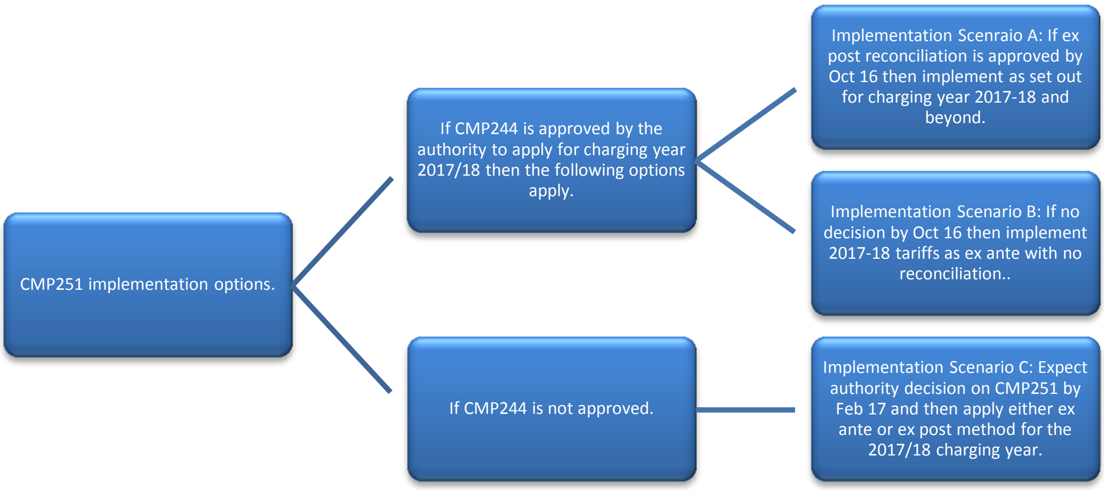
5.3 None identified.

Impact on other Industry Documents

5.4 None identified.

6 Proposed Implementation and Transition

6.1 The following decision tree outlines possible implementation approaches that the Workgroup have considered in the event an ex post reconciliation process is adopted. There is a potential[16] interaction with an existing modification proposal CMP244, which seeks to provide a longer notice period (6-8 months) for the setting of transmission tariffs.



[16] It depends if that proposal is approved and when it (and CMP251, if approved) is implemented.

6.2 For Implementation Scenario A transmission charges for Charging Year 2017/18 and beyond would be set without the use of an error margin, and be subject to an ex post reconciliation meaning that the generation bill for 2017/18 would be recalculated in May 2018 and the demand residual for Charging Year 2019/20 would reflect the under or over recovery of exchange rate risk for Charging Year 2017/18.

6.3 For Implementation Scenario B transmission charges for Charging Year 2017/18 would continue to use the existing ex ante approach. If CMP251 was subsequently approved, transmission charges for Charging Year 2018/19 would be set without the use of an error margin, and be subject to an ex post reconciliation meaning that the generation residual would be recalculated in May 2019 and the demand residual for Charging Year 2020/2021 would reflect the under or over recovery of exchange rate risk in Charging Year 2018/19.

6.4 For Implementation Scenario C, if CMP251 is approved, transmission charges for Charging Year 2017/18 would be set without the use of an error margin, and be subject to an ex post reconciliation meaning that the generation residual would be recalculated in May 2018 and the demand residual for Charging Year 2019/20 would reflect the under or over recovery of exchange rate risk in Charging Year 2017/18. If CMP251 is not approved, the existing ex ante approach would continue to be used.

6.5 For the avoidance of doubt, there will be no reconciliation of Charging Year 2016/17 transmission tariffs even if CMP251 was to be approved.

6.6 The Workgroup noted that in the event an ex post reconciliation is adopted; any reconciliation should include an entirely separate invoicing line/item so that any future adjustments due to the CMP251 reconciliation process are clearly identified.

6.7 It was agreed that the daily spot € exchange rate against sterling values published on the Bank of England website[17] would be used when calculating the actual €/£ outturn in the Charging Year in question.

[17] http://www.bankofengland.co.uk/boeapps/iadb/rates.asp

7 Consultation Responses

7.1 Nine responses were received to the Workgroup Consultation. These responses are contained in Annex 4 of this report.

7.2 The following table provides an overview of the responses received for the standard Workgroup questions;

	Do you believe that CMP254 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?	Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?
EDF Energy	No. The current approach which is based on an ex-ante calculation provides more stability to TNUoS costs.	Yes. If Ofgem approved this modification then we are supportive of the implementation timescales which gives consideration to the potential impact of CMP244.	No.	No.
British Gas	We believe the original proposal better facilitates Applicable CUSC objectives (a), (b) and (c)... (Further comments can be found in Annex 4).	We are supportive of the proposed implementation approach.	No.	No.
RWE Npower	No, we believe that the proposal is detrimental to facilitating CUSC objectives… (Further comments can be found in Annex 4).	We are not supportive of the modification and therefore not supportive of the implementation approach.	No implementation approach specified for an authority decision after October 2016.	Yes. (Further comments can be found in Annex 4).
EON	No, as the change will increase uncertainty of tariffs which could be both detrimental to competition and does not improve cost	Yes.	No.	No.

	reflectivity.			
HIE	We consider that neither the proposal presented in CMP251 nor the potential options better facilitate CUSC objectives. (Further comments can be found in Annex 4).	No response.	No response.	No response.
Scottish Power	We do not believe that the Original Proposal better facilitates the applicable CUSC objectives. (Further comments can be found in Annex 4).	Although we do not support implementation of CMP251 we would support the implementation approach set out in Section 7 of the Workgroup report.	No.	No.
SSE	In our view it is now clear that the baseline CUSC (with the CMP224 based solution) has failed to ensure that there is no exceedance of the €2.5MWh upper limit set in the Regulation. In light of this fact, any practical solution which seeks to correct this will, in our view, better facilitate the Applicable CUSC Objectives; including (b) and (c) but especially (d).	Notwithstanding our comments elsewhere in the response, if CMP251 were to be approved by the Authority then, in our view, it should be implemented at the earliest possible opportunity. (Further comments can be found in Annex 4).	During the first CMP261 Workgroup meeting on 23rd March 2016 National Grid advised that the reconciliation arrangements that they had detailed in paragraph 4.12 of the CMP251 Workgroup consultation document was incorrect. (Further comments can be found in Annex 4).	No.
Smartest Energy	We do not believe that CMP 251 Original Proposal better facilitates any of the Applicable CUSC Objectives.	No.	No.	No.
VPI Immingham	No, we do not believe that the proposal better facilitates the applicable CUSC objectives, (a)	Noting that we do not support the modification overall, should it be implemented, and then we would support the	We have serious concerns regarding the proposed modification. Volatility of charges is a major issue for generators, particularly smaller	No

	and (d). (Further comments can be found in Annex 4).	proposed implementation approach.	independents. (Further comments can be found in Annex 4).	

7.3 : The following table provides an overview of the responses received to the CMP251 specific Workgroup questions:

	Do you have any comments on the legal opinion?	**Is ex-ante certainty preferred over ex-post accuracy?**	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	**Are there trade-offs between speed of reconciliation and the most appropriate process?**
EDF Energy	No.	EDF Energy prefers the ex-ante certainty.	The Original Proposal states that supplier's tariffs would be adjusted with at least 12 months' notice. Dependent on the final mechanism that sets the Euro exchange value certainty could be known much further in advance than this. We are satisfied with this approach.	No.
British Gas	We consider that the legal opinion has not addressed the fact that the error margin in the current approach does not account for exchange rate risk. Whilst we understand the reasons for excluding the exchange rate in the error margin, as set out in CMP 224, we believe it is an	Generators charges for 2015/6 will be above €2.50 on average. CMP 261 has been raised, just a few weeks before the end of the 2015/16 charging year. Whilst we believe that CMP 261 is unnecessary as National Grid used reasonable to ensure compliance for 2015/6, similar modifications may be more capable of	Our original proposal was for the adjustment to occur '*shortly after the end of the charging year*' and reflects the principle that the adjustment should not be unreasonably delayed.	There will be trade-offs and we are comfortable with consideration of other timescales for the generation adjustment if it was deemed that other approaches were legally permissible and offered a better all-round approach.

	important differentiating factor when comparing the two approaches to compliance and the legal opinion has not addressed this. (Further comments can be found in Annex 4).	approval in future years as there is now clear evidence that an ex-ante approach does not ensure average generator charges are below €2.50. This means that the ex-ante approach may not provide the 'certainty' that some members of the Workgroup seem to believe it does.		
RWE Npower	The legal opinion suggests not only that the current (CMP224) approach as legally defendable as the proposal, but it also states the current approach is better in terms of predictability of tariffs and competitiveness within the electricity markets.	Ex ante certainty is preferred over ex post uncertainty and volatility. We will always prefer certainty in tariffs in order to minimise risk premia that may otherwise need to be added to customers' bills.	There should always be a minimum 12 month notice of changes to the under/over recovery of revenue through the k factor.	No, because the most appropriate process does not involve reconciliation.
Eon	We would note reference to the purposive approach taken by the European Court of Justice and adopted by the Courts of England and Wales in interpreting EU Law and when assessing compliance against Regulation 838/2010. We note the conclusions that either an ex ante or ex post method could be shown to be compliant and the conclusion with respect to the current ex ante approach in paragraph 5: "the view that there is a robust argument that the Current Approach ensures compliance with the purpose of the Guidelines Regulation and	Yes. Although we do not think it is necessary to maintain an error margin, particularly in light of the legal advice, in our view CMP251 would add further uncertainty to the costs TNUoS payers are exposed to and undermine the predictability of tariffs.	As quickly as practicable, whilst giving parties adequate notice of any changes in the TNUoS cost base.	Yes, we would not support any process that required a midyear tariff change due to the impacts this would have on TNUoS payers.

	therefore is not vulnerable to legal challenge by dint of taking using ex-ante calculations."			
HIE	No comment.	Ex-ante is preferred to ex-post as it provides more certainty and stability.	No comment.	No comment.
Scottish Power	We concur with the legal opinion that that "both the Current Approach and the BG Approach (CMP251) can facilitate G charges that are compliant with the Guidelines Regulation". However, by reducing uncertainty ex-ante, the current approach better meets the Applicable CUSC Objectives.	Yes. Increased certainty in a competitive market should always lead to lower risk premia and lower costs to consumers.	Notwithstanding our views set out at (6) above, if ex-post reconciliation was to be adopted, the process should be completed as soon as the necessary data is available for both generation and demand tariffs.	As reconciliation amounts relate to a specific Charging Year, any reconciliation amounts applicable to generators (under the Original Proposal) would have to be reflected in the financial statements which cover that Charging Year. An earlier reconciliation process would allow generators to include such amounts, within an acceptable level of materiality, in their financial statements.
SSE	We are mindful that the questions posed to Addleshaw Goddard was on the basis of looking at the future rather that the existing (2015/16 charging year) situation. In that regard it should be noted that the aspects of the legal opinion with respect to an ex-ante approach assumes that it still ensures that the upper limit (of €2.5/MWh) set in the Regulation is not exceeded.	If the ex-ante approach ensured that the upper limit (of €2.5/MWh) set in the Regulation is not exceeded then, in our view, this would be preferred to an ex-post approach as both approaches (ex-ante and ex-post) would ensure that there is no exceedance (of the €2.5/MWh limit) whilst an ex-ante approach would give greater certainty of the level of costs. (Further comments can be found in Annex 4).	In our view the ex-post reconciliation process should be undertaken at the earliest practical opportunity and this should be performed without undue delay on the part of the System Operator after the end of the charging year. (Further comments can be found in Annex 4).	In our view it is not a question of a 'trade-off' but rather one of ensuring that any exceedance of the upper limit (of €2.5/MWh) set in the Regulation is corrected at the earliest practical opportunity. (Further comments can be found in Annex 4).
Smartest Energy	No.	No change is preferred over change.	We can't comment on this as we do not agree with the proposal.	Inevitably. We feel that introducing an additional reconciliation for generation and demand tariffs increases the risk

				premium that generators and suppliers will place on the tariffs forecast and will result overall in less efficient charging.
VPI Immingham	We have no comments on the Legal opinion. We are of the view that the current approach complies with the EU Regulation as it states a range of generator charges from €0 to €2.5/MWh and that this is achieved with the current approach.	Yes, a fixed charge that provides certainty is preferred over a ex-post as it provides certainty to market participants and enables efficient trading.	If the ex-post reconciliation were to proceed, it would make sense for it to be implemented for the next charging year for which the TNUoS charges had not been set, assuming that a robust process could be implemented in the required timescales.	We can see no obvious trade-off for speed of reconciliation versus the most appropriate process.

8 Workgroup Alternatives

8.1 Section 2 of this report highlights the main areas of the Workgroup discussion that could lead to possible alternatives.

8.2 The original proposal seeks to remove the error margin in the cap on total TNUoS recovered by generation and introduce a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010 (Part B) with least impact on GB consumers.

8.3 Before Workgroup Alternatives could be discussed Workgroup members felt that it was important to discuss CMP251 in the context of CMP261. Some Workgroup members felt that they would find it difficult to vote without the visibility of the CMP261 Workgroup legal opinion.

8.4 The concern of certain Workgroup members was that the legal opinion obtained by CMP261 does not fall within the remit of CMP251 and up to this point the legal opinion considered by the CMP251 Workgroup has been the CMP251 legal opinion. A Workgroup member asked the Authority if the Workgroup has provided enough conclusions for the Authority to come to a decision. The Authority confirmed that this is the case.

8.5 The conclusion of the Workgroup was that without the legal opinion for CMP261 available until the next Workgroup meeting on the 21st April 2016 they did not want to delay the progress of CMP251. The Workgroup would progress on the current timeline, the Workgroup Report will be submitted to the April Panel and then the Panel could then make a determination in light of the CMP261 legal advice whether the Workgroup for CMP251 would need to reconvene.

8.6 Discussion began among the Workgroup members whether they wished to raise any WACM Proposals. It was decided by a Workgroup member that all options laid out in the analysis needed to be raised because the reader of the Workgroup Report might be under the impression that these were viable avenues that the Workgroup had considered in its deliberations. The discussion of the Workgroup in light of this view and the responses received resulted in several proposals being discussed by the Workgroup. A variety of other Workgroup members raised WACM Proposals which are detailed in table 1 below:

WACM Proposals	Remove Error Margin	When is the Generator Charge reconciled	When is the Supplier Charge reconciled?	Will it be a 1 way or 2 way reconciliation
Proposal 1	Yes	July Y+1 Tariff Change	July Y+1 Tariff Change	2 Way
Proposal 2	Yes	Y+2 Tariffs	Y+2 Tariffs	1 Way
Proposal 3	Yes	May Y+1 Rebate or Charge	Y+2, Y+3, Y+4 3 Year Average Tariffs through K	2 Way
Proposal 4	Yes	Y+2, Y+3, Y+4 3 Year Average Tariffs	Y+2, Y+3, Y+4 3 Year Average Tariffs through K	2 Way
Proposal 5	Yes	July Y+1 Rebate	July Year +1 Charge	1 Way
Proposal 6	Yes	May Y+1 Rebate	Y+2 Tariffs through K	1 Way
Proposal 7	Yes	Y+2 Tariffs	Y+2 Tariffs	2 Way
Proposal 8	Yes	Rebate May Y+1 Charge Y+2 Tariffs	Y+2 Tariffs through K	2 Way

Table 1 details the WACM Proposals discussed by the Workgroup.

8.7 Following a Workgroup vote the majority of the WACM Proposals were raised as official WACMs. WACM Proposals 2,4,6,7 and 8 were voted to be formalised by the Workgroup members and the Workgroup chair voted to save WACM Proposals 3 and 4 because they only narrowly avoided majority support from the Workgroup (50% or above). You can see the formal WACM numbers in table 2 below:

WACM Number	Remove Error Margin	When is the Generator Charge reconciled	When is the Supplier Charge reconciled?	Will it be a 1 way or 2 way reconciliation
Original	Yes	If Rebate May Y+1 If Charge May Y+1	Y+2 Tariffs	2 way
WACM1	Yes	Y+2 Tariffs	Y+2 Tariffs	1 Way
WACM2	Yes	If Rebate May Y+1 If Charge May Y+1	Y+2, Y+3, Y+4, 3 Year Average Tariffs	2 Way
WACM3	Yes	Y+2, Y+3, Y+4 3 Year Average Tariffs	Y+2, Y+3, Y+4 3 Year Average Tariffs	2 Way
WACM4	Yes	July Y+1 Rebate	July Y +1 Charge	1 Way
WACM5	Yes	May Y+1 Rebate	Y+2 Tariffs	1 Way
WACM6	Yes	Y+2 Tariffs	Y+2 Tariffs	2 Way
WACM7	Yes	If Rebate May Y+1 If Charge Y+2 Tariffs	Y+2 Tariffs	2 Way

Table 2 details the WACMs raised by the Workgroup.

8.8 A detailed description of the WACMs is as follows:

a) **WACM1:** The error margin will be removed and reconciliation will only be carried out if Generators pay more than an average of €2.50/MWh in respect of a Charging Year. Reconciliation will be applied in tariffs of both Suppliers and Generators in Year +2.

b) **WACM2:** The error margin will be removed but reconciliation will be carried out to both Generators and Suppliers to ensure that Generators pay €2.50/MWh in respect of a Charging Year. Generators will receive a rebate or charge in May of Y+1 and the amount to be rebated or charged to Suppliers will be spread over 3 years and recovered through tariffs in Y+2, Y+3 and Y+4. .

c) **WACM3:** The error margin will be removed and reconciliation will be carried out to both Generators and Suppliers to ensure that Generators pay €2.50/MWh in respect of a Charging Year. The amount to be rebated or charged to Generators and Suppliers will be spread over 3 years and recovered through tariffs in Y+2, Y+3 and Y+4.

d) **WACM4:** The error margin will be removed and reconciliation will only be carried out if Generators pay more than an average of €2.50/MWh in respect of a Charging Year. Generators will receive a rebate in July of Y+1 and Suppliers will be charged in July of Y+1.

e) **WACM5:** The error margin will be removed and reconciliation will only be carried out if Generators pay more than an average of €2.50/MWh in respect of a Charging Year. Generators will receive a rebate in May of Y+1 and Suppliers will be charged in the Y+2 tariffs.

f) **WACM6:** The error margin will be removed and reconciliation will be carried out to both Generators and Suppliers to ensure that Generators pay €2.50/MWh in respect of a Charging Year. Reconciliation will be applied in tariffs of both Suppliers and Generators in Year +2.

g) **WACM7:** The error margin will be removed and reconciliation will be carried out to both Generators and Suppliers to ensure that Generators pay €2.50/MWh in respect of a Charging Year. Generators will receive any rebate in May Y+1 and any charge in Y+2 Tariffs, whilst Suppliers receive any rebate or charge in Y+2 Tariffs.

8.9 The table below further simplifies the options

	Only reconcile when €2.50/MWh cap exceeded	**Reconcile to exactly €2.50/MWh**
G+D reconciled at the same time	WACM1 WACM4	WACM3 WACM6
G+D reconciled at different times (G first through rebate or charge and demand later through tariff adjustment)	WACM5	Original WACM2 WACM 7

8.10 The Workgroup then voted against the Original and the 7 WACMs, these votes can be seen in section 6.

9 Workgroup Vote

9.1 The Workgroup believes that the Terms of Reference has been met and that CMP251 has been fully considered.

9.2 For reference the 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 License under Standard Condition C10, paragraph 1.).

9.3 The Workgroup met on the 5th April 2016 and voted on the Original Proposal and the three Workgroup Alternative CUSC Modifications. Six of the Workgroup members voted that the Baseline better facilitated the Applicable CUSC Objectives, two Workgroup members voted for WACM5 and 1 Workgroup member voted for the original solution.

9.4 The votes received are as follows:

National Grid View.

9.5 National Grid considers that CMP251 is not better than the baseline as the current ex ante approach is compliant with Regulation 838/2010. As the legal opinion from Addleshaw Goddard alludes, EU Regulation 838/2010 is purposive and the intent of the Regulation is to promote cross border trade. Given that ex ante tariffs provide price certainty to market participants, the purpose of the Regulation is not consistent with an ex post reconciliation. Furthermore, market participants are consistently advocating to National Grid the importance of predictability and stability of tariffs, and an ex post reconciliation process would work in the opposite direction.

9.6 The agreed industry approach, as implemented in line with the CMP224 Working Group conclusions, considered and excluded the principle of introducing exchange rate risk into transmission tariffs, which is the effect CMP251 would have. The consequences of introducing exchange rate risk, and the uncertainty of an ex post reconciliation would require market participants to include risk premia in their tariff structures to insure against making a loss. This would ultimately increase costs to GB consumers.

9.7 The CMP251 approach of reconciling Generators at a different time to reconciling Suppliers also builds in additional financing costs where National Grid rebates one party and is unable to recover that money for another year or more. These costs are ultimately borne by consumers. If an ex post reconciliation is required, any reconciliation should be coincident between all market players.

Workgroup Member	Applicable CUSC Objectives				
Nick Pittarello	(a)	(b)	(c)	(d)	Overall
Vote 1 (proposal vs baseline)					
Original	No - Legal opinion states the current methodology is compliant with the Regulation. Ex post reconciliation would be detrimental to competition and introduction of exchange rate risk will lead to higher costs to GB consumers	No	No	No	No
WACM1	No – as per the comment on the Original	No	No	No	No
WACM2	No - as per the comment on the Original	No	No	No	No
WACM3	No - as per the comment on the Original	No	No	No	No
WACM4	No - as per the comment on the Original	No	No	No	No
WACM5	No - as per the comment on the Original	No	No	No	No
WACM6	No - as per the comment on the Original	No	No	No	No
WACM7	No - as per the comment on the Original	No	No	No	No
Vote 2 (Each WACM vs original)					
WACM1	Yes - consistent industry process, no cashflow problems and also	Neutral	Yes – exchange rate	Neutral	Yes

	stability. Avoids exchange rate risk.				
WACM2	No – complicated with scope for confusion creating a barrier for entry. Two way reconciliation unnecessary and cashflow financing costs.	Neutral	No	Neutral	No
WACM3	Yes - suppliers and generators enough notice for change	Neutral	Neutral	Neutral	Yes
WACM4	No – not enough time for suppliers to adjust their charges.	Neutral	Neutral	Neutral	No
WACM5	No -reconciliation at different times adds financing costs	Neutral	Neutral	Neutral	No
WACM6	No - prefer 1 way to 2 way reconciliation as only carrying out a rec if it's an exceedance is more logical	Neutral	Neutral	Neutral	No
WACM7	No – does not like the inconsistency of treatment between Generators and Demand and its also 2 way.	Neutral	No – National Grid exchange rate risk in the K	Neutral	No
Vote 3 (Which best meets applicable CUSC objectives)					
National Grid					Baseline is the best because the legal opinion states an ex ante approach is consistent with delivering the regulation, it also delivers predictably and stability whilst deliberately excluding exchange rate risk. An ex post reconciliation is the opposite of the stability and predictability desired by

					market participants and could lead to additional risk premium being introduced to tariffs resulting in higher costs to GB consumers.

Workgroup Views.

Workgroup Member	Applicable CUSC Objectives				
Garth Graham	**(a)**	**(b)**	**(c)**	**(d)**	**Overall**
Vote 1 (proposal vs baseline)					
Original	Yes – by having legal compliance this ensures that we are enhancing competition	Yes – by having legal compliance this ensures that we are enhancing competition	Neutral	Yes – clear from the legal opinion that we have an issue with compliance under the baseline which needs to be addressed - which this proposal does	Yes
WACM1	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes – as per the comment on the Original	Yes
WACM2	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes – as per the comment on the Original	Yes
WACM3	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes – as per the comment on the Original	Yes
WACM4	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes – as per the comment on the Original	Yes

WACM5	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes – as per the comment on the Original	Yes
WACM6	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes – as per the comment on the Original	Yes
WACM7	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes – as per the comment on the Original	Yes
Vote 2 (Each WACM vs original)					
WACM1	No	No	Neutral	Neutral	No
WACM2	No	No	Neutral	Neutral	No
WACM3	No	No – exceedance recovered three or four years after event	Neutral	Neutral	
WACM4	No	Yes – as exceedance are recovered in y+1	Neutral	Yes – clear from the legal opinion that we have an issue with compliance under the baseline which needs to be addressed - which this proposal does	Yes
WACM5	Yes	Yes - as exceedance are recovered in y+1	Neutral	Yes – clear from the legal opinion that we have an issue with compliance under the baseline which needs to be addressed - which this proposal does	Yes
WACM6	No	No – y+2 exceedance recovery	Neutral	Neutral	No
WACM7	Yes	Yes - as exceedance are	Neutral	Yes – clear from the legal opinion that we have an	Yes

		recovered in y+1		issue with compliance under the baseline which needs to be addressed - which this proposal does	
Vote 3 (Which option best facilitates CUSC objectives)					
Baseline					
Original					
WACM1					
WACM2					
WACM3					
WACM4					
WACM5					Yes
WACM6					
WACM7					

Workgroup Member	Applicable CUSC Objectives				
Peter Bolitho	(a)	(b)	(c)	(d)	Overall
Vote 1 (proposal vs baseline)					
Original	No – ordinarily an ex ante approach to setting charges is preferable.	Neutral	Neutral	Yes – there is now clearly an issue with compliance with the Regulation - an ex post reconciliation	Yes

				process addresses this.	
WACM1	No – as per the comment on the Original	Neutral	Neutral	Yes – as per the comment on the Original	Yes
WACM2	No – as per the comment on the Original	Neutral	Neutral	Yes – as per the comment on the Original	Yes
WACM3	No – as per the comment on the Original	Neutral	Neutral	Yes – as per the comment on the Original	Yes
WACM4	No – as per the comment on the Original	Neutral	Neutral	Yes – as per the comment on the Original	Yes
WACM5	No – as per the comment on the Original	Neutral	Neutral	Yes – as per the comment on the Original	Yes
WACM6	No – as per the comment on the Original	Neutral	Neutral	Yes – as per the comment on the Original	Yes
WACM7	No – as per the comment on the Original	Neutral	Neutral	Yes – as per the comment on the Original	Yes
Vote 2 (Each WACM vs original)					
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	No	Neutral	Neutral	Neutral	No
WACM3	No	Neutral	Neutral	Neutral	No
WACM4	No	Neutral	Neutral	Neutral	No
WACM5	Yes – this seeks to address the overcharging of generators which needs to be done as soon as possible, but also addresses the concern of suppliers not having to face paying the costs so soon after	Neutral	Neutral	Neutral	Yes

	the charging year				
WACM6	No	Neutral	Neutral	Neutral	No
WACM7	No	Neutral	Neutral	Neutral	No
Vote 3 (Which option best facilitates CUSC objectives)					
Baseline					
Original					
WACM1					
WACM2					
WACM3					
WACM4					
WACM5					Yes – this seeks to address the overcharging of generators which needs to be done as soon as possible, but also addresses the concern of suppliers not having to face paying the costs so soon after the charging year.
WACM6					
WACM7					

Workgroup	**Applicable CUSC Objectives**	

Member					
James Anderson	(a)	(b)	(c)	(d)	Overall
Vote 1 (proposal vs baseline)					
Original	No	Neutral	Neutral	Neutral	No
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	No	Neutral	Neutral	Neutral	No
WACM3	No	Neutral	Neutral	Neutral	No
WACM4	No	Neutral	Neutral	Neutral	No
WACM5	No	Neutral	Neutral	Neutral	No
WACM6	No	Neutral	Neutral	Neutral	No
WACM7	No	Neutral	Neutral	Neutral	No
Vote 2 (Each WACM vs original)					
WACM1	No	Neutral	Neutral	Neutral	No
WACM2	No	Neutral	Neutral	Neutral	No
WACM3	No	Neutral	Neutral	Neutral	No
WACM4	No	Neutral	Neutral	Neutral	No
WACM5	No	Neutral	Neutral	Neutral	No
WACM6	No	Neutral	Neutral	Neutral	No
WACM7	No	Neutral	Neutral	Neutral	No

Vote 3 (Which option best facilitates CUSC objectives)					
Baseline					Yes – following the legal opinion, the ex ante approach is suitable to achieve compliance and the ex post approach will only create further uncertainty of costs.
Original					
WACM1					
WACM2					
WACM3					
WACM4					
WACM5					
WACM6					
WACM7					

Workgroup Member	**Applicable CUSC Objectives**				
Cem Suleyman	**(a)**	**(b)**	**(c)**	**(d)**	**Overall**
Vote 1 (proposal vs baseline)					
Original	No - CMP251 creates an ex post reconciliation which promotes the precise opposite of the stability and	Neutral	Neutral	Neutral - The legal opinion states that either an ex ante or an ex post	No

	predictability associated with the current approach. CMP251 will tend to result in the introduction of risk premia and ineffective competition. These impacts will likely result in negative consequences for consumers			approach may be adopted. As such the current ex ante method complies with the Regulation. There is no benefit associated with switching to an ex post approach.	
WACM1	No – as per the comment on the Original	Neutral	Neutral	Neutral - as per the comment on the Original	No
WACM2	No – as per the comment on the Original	No – 3 year average reduces cost reflectivity	Neutral	Neutral - as per the comment on the Original	No
WACM3	No – as per the comment on the Original	No – 3 year average reduces cost reflectivity	Neutral	Neutral - as per the comment on the Original	No
WACM4	No – as per the comment on the Original	Neutral	Neutral	Neutral - as per the comment on the Original	No
WACM5	No – as per the comment on the Original	Neutral	Neutral	Neutral - as per the comment on the Original	No
WACM6	No – as per the comment on the Original	Neutral	Neutral	Neutral - as per the comment on the Original	No
WACM7	No – as per the comment on the Original	Neutral	Neutral	Neutral - as per the comment on the Original	No
Vote 2 (Each WACM vs original)					
WACM1	Yes – The use of a one way reconciliation reduces the negative impact of introducing an ex post approach.	Neutral	Yes - National Grid avoids cost of carry implications	Neutral	Yes

WACM2	No – unnecessarily complicated. Risks creating a small barrier to entry.	No – 3 year average means unable to justify cost reflectivity	Neutral	Neutral	No
WACM3	No – unnecessarily complicated. Risks creating a small barrier to entry.	No – 3 year average reduces cost reflectivity	Yes - National Grid avoids cost of carry implications	Neutral	Yes
WACM4	Yes – The use of a one way reconciliation reduces the negative impact of introducing an ex post approach. Moreover, an early financial transfer will ensure that power stations which close in the following charging year receive recompense where relevant. Suppliers are able to efficiently fund financial transfers where FX hedges have been employed, reducing any detrimental impact on competition in Supply.	Neutral	Yes - National Grid avoids cost of carry implications	Neutral	Yes
WACM5	Yes – The use of a one way reconciliation reduces the negative impact of introducing an ex post approach.	Neutral	Neutral	Neutral	Yes
WACM6	Neutral	Neutral	Yes - National Grid avoids cost of carry implications	Neutral	Yes
WACM7	Neutral	Neutral	Yes - National Grid cost of carry implications are reduced	Neutral	Yes
Vote 3 (Which option best facilitates CUSC objectives)					

Baseline					Baseline is the best because the legal opinion states an ex ante approach ensures compliance with the regulation. It also delivers predictably and stability whilst deliberately excluding exchange rate risk. This better facilitates effective competition delivering better outcomes for consumers.
Original					
WACM1					
WACM2					
WACM3					
WACM4					
WACM5					
WACM6					
WACM7					

Workgroup Member	Applicable CUSC Objectives				
Binoy Dharsi	**(a)**	**(b)**	**(c)**	**(d)**	**Overall**

Vote 1 (proposal vs baseline)					
Original	No - Ex-ante approach brings stability which is something we value more than ex-post reconciliation	Neutral	Neutral	Neutral	No
WACM1	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM2	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM3	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM4	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM5	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM6	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM7	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
Vote 2 (Each WACM vs original)					
WACM1	Yes - Gives more notice to suppliers to adjust tariffs for customers. One way approach means that action is only taken upon breach of the cap.	Neutral	Neutral	Neutral	Yes
WACM2	No - spreading the cost over a 3 year average is excessive for what	Neutral	Neutral	Neutral	No

	is likely to be a relatively small amount of money against the entire allowed revenue.				
WACM3	No - same reason as above	Neutral	Neutral	Neutral	No
WACM4	No - do not support a suppliers reconciliation at Y+1…not enough notice	Neutral	Neutral	Neutral	No
WACM5	Yes- Gives more notice to suppliers to adjust tariffs for customers. One way approach means that action is only taken upon breach of the cap.	Neutral	Neutral	Neutral	Yes
WACM6	No - On balance do not support as two way means that reconciliation is required when within the cap	Neutral	Neutral	Neutral	No
WACM7	Yes - Gives more notice to suppliers to adjust tariffs for customers. One way approach means that action is only taken upon breach of the cap.	Neutral	Neutral	Neutral	Yes
Vote 3 (Which option best facilitates CUSC objectives)					
Baseline					Yes - as ex-ante approach removes uncertainty. Overtime we believe error margin should start trending to a lower value as forecasting from National Grid improves.
Original					
WACM1					

WACM2					
WACM3					
WACM4					
WACM5					
WACM6					
WACM7					

Workgroup Member	**Applicable CUSC Objectives**				
George Douthwaite	**(a)**	**(b)**	**(c)**	**(d)**	**Overall**
Vote 1 (proposal vs baseline)					
Original	No – things are becoming less predictable with the potential requirement of risk premium	No – following the end of year you have lost suggestion of cost reflectivity	Neutral	No – legal opinion shows we are ok	No
WACM1	No – as per the comment on the Original	No – as per the comment on the Original	Neutral	No – as per the comment on the Original	No
WACM2	No – as per the comment on the Original	No – as per the comment on the Original	Neutral	No – as per the comment on the Original	No
WACM3	No – as per the comment on the Original	No – as per the comment on the Original	Neutral	No – as per the comment on the Original	No

WACM4	No – as per the comment on the Original	No – as per the comment on the Original	Neutral	No – as per the comment on the Original	No
WACM5	No – as per the comment on the Original	No – as per the comment on the Original	Neutral	No – as per the comment on the Original	No
WACM6	No – as per the comment on the Original	No – as per the comment on the Original	Neutral	No – as per the comment on the Original	No
WACM7	No – as per the comment on the Original	No – as per the comment on the Original	Neutral	No – as per the comment on the Original	No
Vote 2 (Each WACM vs original)					
WACM1	No	No – following the end of year you have lost suggestion of cost reflectivity	Neutral	Neutral	No
WACM2	Yes - worse that the Original where 1-way reconciliation is involved.	Neutral	Neutral	Neutral	Yes
WACM3	Yes - Better than the original where longer notification time is given	Neutral	Neutral	Neutral	Yes
WACM4	No	Neutral	Neutral	Neutral	No
WACM5	No	Neutral	Neutral	Neutral	No
WACM6	Yes - Better than the original when generation reconciliation occurs closer in time to the changes to demand tariffs.	Neutral	Neutral	Neutral	Yes

WACM7	Yes - Better than the original when generation reconciliation occurs closer in time to the changes to demand tariffs.	Neutral	Neutral	Neutral	Yes
Vote 3 (Which option best facilitates CUSC objectives)					
Baseline					Yes - offers most predictability and therefore best competition as there is no reopening of the published tariffs,
Original					
WACM1					
WACM2					
WACM3					
WACM4					
WACM5					
WACM6					
WACM7					

I felt that all the options were neutral in terms of (c) developments on the network.

I felt that all the options were neutral in terms of (d) European legislation. My response contains the reasoning for this; basically we feel that the legal opinion supports the use of ex-ante approach. We feel that this is defendable as the tariffs need to be set before the year starts, and the approach attempts to meet the legislation while at the same time trying to keep some predictability and stability in the charges.

Regarding (b) Cost reflectivity. As soon as the year has ended, charges applied within a subsequent charging year are no longer cost reflective. We would not support mid-year tariff changes because of the volatility and unpredictability this would add to the charging. We do not believe that the length of time after the year end makes much difference to cost reflectivity once the applicable tariff year has ended. Furthermore, with reconciliation rebates, we are not aware of the mechanism that ensures the relevant overpayment is passed back to the customers, especially as the 2.5 Euro cap does not apply at an individual customer level. Therefore we do not see any of the original or proposals being better than the baseline in terms of cost-reflectivity.

Regarding competition, we believe that less predictable costs have two effects. It increases the variation between prices offered by various suppliers, and in this sense increases competition through greater choice. However, this generally will increase these prices, therefore making the charges less competitive, and a greater financial burden, to all customers. We therefore feel that increasing time of notification of changes to charges keeps any supplier risk premia lower, and therefore keeps the future rates charged to customers lower, or more competitive.

Any option which reopens published rates will add to uncertainty. Having a time disparity between reconciliation of generator charges and subsequent offsetting on suppliers through tariff changes adds cost as the reconciliation costs will need to be held by National Grid for a period of time.

The baseline and all alternatives add unnecessary complexity to the process, therefore adding time and cost to the processes of all market participants.

2 way settlement (reconciliation to generators as either a credit or debit up to the 2.5 Euro limit) has the advantage that over the long term, this should average to 0. Therefore long term risk premia can be lower than the case of a 1 way reconciliation based on only credits to the generators and no debits.

Workgroup Member	Applicable CUSC Objectives				
George Moran	(a)	(b)	(c)	(d)	Overall
Vote 1 (proposal vs baseline)					
Original	Yes - Reduces uncertainty since: (1) Removes the risk associated with unexpected changes to the error margin. (2) Provides certainty of compliance with the Regulation. (3) Provides upfront certainty that an adjustment will occur, enabling parties to monitor and take appropriate steps. This is better than the current situation where parties don't know if reconciliations will be required which significantly hinders effective competition.	Yes – minimises the distortion of the default cost reflective charging principles (G:D split)	Yes – this mod will ensure that National Grid take steps to learn from the first year of CMP244	Neutral	Yes
WACM1	Yes - as per the comment on the Original although caveat is that delay in the reconciliation potentially reduces certainty of compliance	Yes – as per the comment on the Original, although more limited benefit as adjustment is one way	Yes – as per the comment on the Original	Neutral	Yes
WACM2	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes

WACM3	Yes –as per the comment on the Original although caveat is that delay in the reconciliation potentially reduces certainty of compliance	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes
WACM4	No – disadvantage of no notice period for supplier reconciliation outweighs the benefits of reducing the risk of non compliance and the risk of changes to the error margin.	Yes - as per the comment on the Original, although more limited benefit as adjustment is one way	Yes - as per the comment on the Original	Neutral	No – the negative impact on competition from the lack of notice for the supplier reconciliation outweighs the positive impact on the other objectives.
WACM5	Yes – as per the comment on the Original	Yes - as per the comment on the Original, although more limited benefit as adjustment is one way	Yes – as per the comment on the Original	Neutral	Yes
WACM6	Yes – as per the comment on the Original although caveat is that delay in the reconciliation potentially reduces certainty of compliance	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes
WACM7	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Yes – as per the comment on the Original	Neutral	Yes
Vote 2 (Each WACM vs original)					
WACM1	No	No	No	No	No
WACM2	No	No	No	No	No
WACM3	No	No	No	No	No
WACM4	No	No	No	No	No

WACM5	No	No	No	No	No
WACM6	No	No	No	No	No
WACM7	No	No	No	No	No
Vote 3 (Which option best facilitates CUSC objectives)					
Baseline					
Original					Yes: (1) minimises the transfer of costs between Generators and consumers (2) removes uncertainty associated with changes to the error margin (3) provides upfront certainty that a reconciliation will occur (4) provides certainty of compliance with the Regulation (5) minimises the distortion of the cost reflective default charging principles (G:D split) (6) allows Grid to take account of developments in its business.
WACM1					
WACM2					
WACM3					
WACM4					
WACM5					

WACM6					
WACM7					

Workgroup Member	**Applicable CUSC Objectives**				
Guy Phillips	**(a)**	**(b)**	**(c)**	**(d)**	**Overall**
Vote 1 (proposal vs baseline)					
Original	No - Stability and predictability supported by the legal opinion	Neutral	Neutral	Neutral	No
WACM1	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM2	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM3	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM4	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM5	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM6	No – as per the comment on the Original	Neutral	Neutral	Neutral	No
WACM7	No – as per the comment on the Original	Neutral	Neutral	Neutral	No

Vote 2 (Each WACM vs original)					
WACM1	Yes – 1 way rec provides more stability and it does not need to specifically 2.50 according to the Regulation	Neutral	Neutral	Neutral	Yes
WACM2	No – too complex	No	Neutral	Neutral	No
WACM3	Same as above	Neutral	Neutral	Neutral	No
WACM4	No – does not give suppliers sufficient notice to adjust to a change in cost	Neutral	Neutral	Neutral	No
WACM5	Yes – gives suppliers sufficient notice to adjust to a change in cost	Neutral	Neutral	Neutral	Yes
WACM6	Neutral	No – year 2 tariff adjustment does not allow the money to go back to parties who should have received it	Neutral	Neutral	No
WACM7	No	Neutral	Neutral	Neutral	No
Vote 3 (Which option best facilitates CUSC objectives)					
Baseline					Baseline is the best because a legal opinion states an ex ante approach is consistent with delivering the regulation, it also delivers predictably and stability of tariffs which better facilitates competition.
Original					
WACM1					

WACM2					
WACM3					
WACM4					
WACM5					
WACM6					
WACM7					

Annex 1 – CMP251 CUSC Modification Proposal Form

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP251

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal

Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010.

Submission Date

19th August 2015

Description of the Issue or Defect that the CUSC Modification Proposal seeks to address

European Commission Regulation 838/2010 states a range of 0 - 2.5 €/MWh that average annual transmission charges payable by generators in GB must remain within. If in any given year the average annual generation transmission charges do not fall within this range, National Grid risks being non-compliant with the regulation.

In order to combat this risk, National Grid raised a modification (CMP 224) in September 2013. CMP 224 was approved by Ofgem and implemented in October 2014.

Under the current charging methodology, as amended by CMP 224, TNUoS tariffs are set to result in the overall revenue received from GB generation being the lesser of:

- 27% of the total revenue to be recovered from GB Users via TNUoS tariffs; or
- such a value that results in generation tariffs not exceeding the upper limit specified under the EC Regulation (currently €2.5 /MWh), **after an adjustment for an 'error margin' to deal with forecast error**.

Whilst CMP 224 reduces the risk of non-compliance with the EC regulation, it does not remove it entirely since TNUoS charges are set ahead of the charging year based on forecast variables which can be difficult to accurately predict.

There remains a risk that annual charges may exceed the 2.5 €/MWh cap currently specified by the regulation. For instance, if the Euro/pound exchange rate remains at the level observed since April 2015 (an average of 1.38 for the period 1 April to 30 June) then the cap would be exceeded in 2015/16 (holding all other assumptions constant), as demonstrated below:

National Grid 2015/16 Tariff Setting Assumptions:
Total TNUoS Revenue for 2015/16: £2,637m
Generation Revenue Recovery for 2015/16: £612m
Forecast generation: 319.6 GWh
Assumed Euro/pound exchange rate: 1.22

Assumed Generator €/MWh: (612 *1.22)/319.6 = **2.34** €/MWh

TNUoS charge level adjusted for current exchange rate:
Current (April 15 - June 15) Euro/pound exchange rate: 1.38
Latest forecast Generator €/MWh: (612 * 1.38)/319.6 = **2.65** €/MWh

It can be seen that whilst the methodology implemented by CMP 224 uses reasonable endeavours to comply with European Commission Regulation 838/2010, there remains a risk that average annual transmission charges may exceed 2.50 €/MWh in some circumstances. There is a need for a further methodology change to ensure that compliance with the regulation in future is not dependent on the accuracy of forecasts.

The only purpose of CMP224 was to manage compliance with European Commission Regulation. The result of CMP224 was to alter the charges that would otherwise have resulted from the application of charging methodology. The underpinning principles of the charging methodology, including the default split of revenue between generators and demand users, were not affected by CMP224. Therefore, the application of a cap distorts the principles of the charging methodology. By removing the error margin, our proposed solution will therefore also reduce the distortive effect on charges of the 2.50 €/MWh cap.

In practice the distortive impact on the G:D split is to transfer costs from generation to demand. In the CMP224 decision, Ofgem was clear that there was a risk that the transfer of costs from generation to demand has a negative impact on consumers. By removing the error margin our proposed solution will reduce this risk.

Description of the CUSC Modification Proposal

As specified in the EC regulation, the value for average annual transmission charges payable by generators is calculated by dividing the total revenue collected from generation users through Transmission Network Use of System (TNUoS) charges by the total measured energy injected into the Transmission Network or simply the total demand for that year.

CUSC Section 14 Part – 2 specifies that the total Transmission Network Use of System (TNUoS) revenue recovered from generators will be the lower of:

- 27%, or
- A percentage (x) calculated as

$$x_n = \frac{(Cap_{EC} * (1 - y)) * GO}{MAR * ER}$$

Where:
CapEC = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation
y = Error margin built in to adjust CapEC to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n
GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n
MAR = Forecast TO Maximum Allowed Revenue (£) for charging year n

ER = OBR Spring Forecast €/£ Exchange Rate in charging year n-1

The proposal aims to ensure that the risk of non-compliance is removed with least impact on GB consumers.

The proposal is to remove any error margin from the above equation (i.e. set the y term to zero) when setting initial TNUoS charges and also introduce a new element to the TNUoS charging methodology. The new element would be a single adjustment which guaranteed compliance with the regulation. The adjustment would be calculated shortly after the end of the charging year and would be set at an amount which would ensure that the average amount charged to GB generators would be equal to the lesser of the percentage of revenue to be recovered from generators (currently 27%) or the absolute cap allowed by the regulation (currently 2.50 €/MWh).

For the avoidance of doubt, the adjustment could be either a charge or a credit to generators depending on the out turn values for the relevant variables (i.e. revenue recovered, generation volumes, average exchange rate) compared to the assumptions used to set initial charges.

The adjustment to generators (whether a charge or a credit) would be treated as either additional or reduced (as appropriate) recovered TNUoS revenue for the charging year to which the adjustment relates and would affect the over/under recovery position, with demand customers effectively picking up the reverse of the adjustment in future years TNUoS tariffs.

We consider that this proposal:

- Provides certainty that the regulation will be complied with
- Minimises the impact on the principles underpinning the TNUoS tariffs
- Minimises the required transfer of costs from generators to consumers
- Provides predictability for generators that the average TNUoS charges will be set to recover the cap set by the regulation (currently 2.50 €/MWh), unless this would recover greater than the percentage of revenue (currently 27%) of overall TNUoS revenue
- Provides predictability to suppliers of the impact on future year tariffs (by capturing the generator adjustment within the over/under recovery position)

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

As demonstrated above, whilst the current methodology uses reasonable endeavours to comply with European Commission Regulation 838/2010 there remains a real risk that average annual transmission charges may exceed 2.50 €/MWh in some circumstances. There is an urgent need for a further methodology change to ensure that compliance with the regulation in future is not dependent on the accuracy of forecasts. Therefore we consider it is necessary to expedite this change to allow for implementation for the TNUoS charges applicable from 2016/17.

Self-Governance Recommended: Yes / No

No

Justification for Self-Governance Recommendation

N/A

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

We believe that this proposal does not have any interaction with an ongoing SCR

Impact on Computer Systems and Processes used by CUSC Parties:

Unknown.

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:

The European Commission Regulation 838/2010 is legally binding for all Transmission licensees across Europe. We believe that this proposal ensures that National Grid remains compliant with the European legislation and properly reflects National Grid’s duties in the development of its transmission business.

The principles underpinning the charging methodology, including the default proportion of revenue to be recovered from generators, are approved as meeting objective (b) above. Therefore, any unnecessary restrictions on how these principles are translated into charges are detrimental to meeting objective (b). The error margin included in the current methodology represents an unnecessary restriction on the underlying principles of the methodology since it applies a cap which goes above and beyond the cap stated in the regulation. By minimising the impact of compliance with 838/2010 objective (b) is better met.

CMP224 also sought to 'properly take account of developments in the transmission licensees' transmission business', however it has proven to be sub-optimal in two respects:

(1) CMP 224 goes above and beyond the cap stated in the regulation to the detriment of consumers
(2) CMP 224 does not provide sufficient assurance that the regulation will not be breached

The modification we propose here will rectify these short-comings.

Additional details

Details of Proposer: (Organisation Name)	British Gas
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:	George Moran British Gas 07557 611983 George.moran@britishgas.co.uk
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Andy Manning British Gas 07789 575 553 Andy.manning@britishgas.co.uk
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 – CMP251 Terms of Reference

CMP251 aims to ensure that there is no risk of non-compliance with European Regulation 838/2010 by removing the error margin introduced by CMP224 and by introducing a new charging element to the calculation of TNUoS.

Responsibilities

1. **The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal** 'Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010' **tabled by British Gas at the CUSC Modifications Panel meeting on 28th August 2015.**

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.

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) *Implementation*

   b) *Review draft legal text*

   c) *Consider the legality of breaching the regulation then reconciling the difference the following year.*

   d) *Consider whether you should fix the charge at €2.5 as proposed rather than remaining within the €0-€2.5 range as per the EC Regulation.*

   e) *Assess impact on competition*

   f) *Consider any interaction with CMP244.*

   g) *Consider when €2.50 is to be calculated.*

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 15 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 18th February 2016 for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on 26th February 2016.

Membership

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

Role	Name	Representing
Chairman	John Martin	Code Administrator
*National Grid Representative**	Nick Pittarello	National Grid

*Industry Representatives**	George Moran	British Gas
	Garth Graham	SSE
	Jon Wisdom	NPower
	George Douthwaite	Npower
	Lisa Waters	Waters Wye
	Peter Bolitho	Waters Wye
	Cem Suleyman	Drax Power
	Binoy Dharsi	EDF
	James Anderson	Scottish Power
	Guy Phillips	Uniper
	Jeremy Guard	First Utility
Authority Representatives	Donald Smith	Ofgem
Technical secretary	Ryan Place	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 CMP251 is that at least 5 Workgroup members must participate in a meeting for quorum to be met.

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

- Vote 1: whether each proposal better facilitates the Applicable CUSC Objectives;
- Vote 2: where one or more WACMs exist, whether each WACM better facilitates the Applicable CUSC Objectives than the original Modification Proposal;

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

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

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

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

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

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

Appendix 1 – Indicative Workgroup Timetable

The following timetable is indicative for CMP251

7TH September 2015	Deadline for comments on Terms of Reference / nominations for Workgroup membership
28th September 2015	Workgroup meeting 1
26th November 2015	Workgroup meeting 2
26th November 2015	Workgroup meeting 2
14th December 2015	Workgroup Consultation issued for comment
4th January 2016	Deadline for comment

11th January 2016	Workgroup meeting 3
3rd February 2016	Workgroup meeting 4
9th February 2016	Workgroup meeting 5
24th February 2016	Workgroup meeting 6
29th February 2016	Workgroup Consultation published
29th March 2016	Deadline for comment
5th April 2016	Workgroup meeting 7
21st April 2016	Submit final Workgroup Report to Panel
29th April 2016	Present Workgroup Report at CUSC Modifications Panel
27th May 2016	Workgroup meeting 8
16th June 2016	Submit final Workgroup Report to Panel
24th June 2016	Present Workgroup Report at CUSC Modifications Panel

*please note that the Workgroup Report was sent back to Workgroup in May to consider the impact of the CMP261 legal advice.

Post Workgroup modification process

28th June 2016	Code-Administrator Consultation published (15days)
19th July 2016	Deadline for responses
26th July 2016	Draft FMR published
2nd August 2016	Deadline for comments
18th August 2016	Draft FMR issued to CUSC Panel
26th August 2016	CUSC Panel Recommendation vote
6th September 2016	Final CUSC Modification Report submitted to Authority

Annex 3 – Workgroup attendance register

A – Attended

X – Absent

O – Alternate

D – Dial-in

Name	Organisation	Role	28th September 2015	26th November 2015	11th January 2016	3rd February 2016	9th February 2016	24th February 2016	5th April 2016	27th May 2016
John Martin	Code Administrator	Chair	A	A	A	D	D	D	A	A
Heena Chauhan	Code Administrator	Technical Secretary	A	X	X	X	X	X	X	X
Ryan Place	Code Administrator	Technical Secretary	A	A	A	D	D	D	A	A
George Moran	British Gas	Proposer	A	A	A	D	D	D	A	A
Nick Pittarello	National Grid	Workgroup member	A	A	A	D	D	D	A	A
Garth Graham	SSE	Workgroup member	A	A	A	D	D	D	A	A
Jon Wisdom	Npower	Workgroup member	X	X	X	X	X	X	X	X
Lisa Waters	Waters Wye	Workgroup member	X	X	X	X	X	X	X	X
Cem Suleyman	Drax	Workgroup member	A	D	A	D	D	D	A	A
Binoy Dharsi	EDF	Workgroup member	A	A	A	D	D	D	A	D

James Anderson	Scottish Power	Workgroup member	A	A	A	D	D	D	X	X
Guy Phillips	Eon	Workgroup member	A	A	X	D	D	D	A	A
George Douthwaite	Npower	Alternate	O	O	O	OD	OD	OD	O	O
Peter Bolitho	Waters Wye	Alternate	O	O	O	OD	OD	OD	O	O
Jeremy Guard	First Utilty	Workgroup member	X	X	X	X	X	X	A	X
Donald Smith	Ofgem	Authority Representative	A	A	A	D	D	D	A	D

Annex 4 – Workgroup Consultation Responses

CUSC Workgroup Consultation Response Proforma

CMP251 – Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010.

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 **29th March 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 Ryan Place at ryan.place@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:	*Binoy Dharsi (binoy.dharsi@edfenergy.com)*
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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?**	No. The current approach which is based on an ex-ante calculation provides more stability to TNUoS costs.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Yes. If Ofgem approved this modification then we are supportive of the implementation timescales which gives consideration to the potential impact of CMP244.
3	**Do you have any other comments?**	
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No.

Specific questions for CMP251

Q	Question	Response
6	**Do you have any comments on the legal opinion?**	No comment.
6	**Is ex ante certainty preferred over ex post accuracy?**	EDF Energy prefers the ex ante certainty.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	The Original Proposal states that supplier's tariffs would be adjusted with at least 12 months' notice. Dependent on the final mechanism that sets the Euro exchange value certainty could be known much further in advance than this. We are satisfied with this approach. For Generators the Original Proposal states that generators are required to be settled as soon as practically possible after the relevant Charging Year. We are satisfied with this approach.
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	No comment.

CUSC Workgroup Consultation Response Proforma

CMP251 – Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010.

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Any queries on the content of the consultation should be addressed to Ryan Place at ryan.place@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:	*George Moran* *British Gas* *George.moran@britishgas.co.uk*
Company Name:	*British Gas*
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.

Standard Workgroup consultation questions

Q	Question	Response

<table>
<tr><th>Q</th><th>Question</th><th>Response</th></tr>
<tr><td>1</td><td>Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?</td><td>
Original Proposal:
We believe the original proposal better facilitates Applicable CUSC objectives (a), (b) and (c).

Applicable objective (a):
Recent developments demonstrate the benefit that CMP 251 would provide to effective competition in the generation and supply of electricity.

Generators charges for 2015/6 will be above €2.50 on average. Modification proposal CMP 261 has been raised, just a few weeks before the end of the year, and seeks to retrospectively bring in a reconciliation. We do not believe any adjustment is necessary for 2015/16 since National Grid used reasonable endeavours to ensure compliance with the Regulation. However, there is now clear evidence that an ex-ante approach, whilst remaining compliant for 2015/6, does not ensure that average generator charges are below €2.50. This means that if an ex-ante approach is maintained this may no longer represent reasonable endeavours prospectively.

This means that modification proposals similar to CMP 261 may be more capable of being adopted in future years. Effective competition is significantly hindered if the market does not know whether an adjustment will occur.

CMP 251 represents a sensible approach to removing any uncertainty going forward by introducing an adjustment that would ensure compliance and provide all market participants with certainty in advance that such an adjustment will occur. The table below presents our assessment of uncertainty under the current baseline methodology and whether this is improved or not under CMP 251.

<table>
<tr><th></th><th>Baseline</th><th>CMP 251</th></tr>
<tr><td>Changes to Error Margin</td><td>Uncertainty under baseline methodology</td><td>CMP 251 removes this uncertainty</td></tr>
<tr><td>Compliance with Regulation</td><td>Uncertain whether baseline is compliant if €2.50 cap is exceeded frequently</td><td>CMP 251 achieves a more certain and precise alignment with the G Charge Guidelines</td></tr>
<tr><td rowspan="2">Exchange Rate Uncertainty Short Term</td><td>If baseline methodology guarantees no adjustment/mid-year tariff change then no risk</td><td>CMP 251 introduces a new uncertainty in the form of the adjustment</td></tr>
<tr><td>If baseline methodology does not guarantee no adjustment/mid-year tariff change then significant risk</td><td>CMP 251 ensures all market participants have certainty that an adjustment will occur and removes risk of unanticipated mid-year tariff changes</td></tr>
<tr><td>Exchange Rate Uncertainty Long Term</td><td>Long term exchange rate uncertainty is a feature of the baseline methodology</td><td>No Change</td></tr>
</table>
</td></tr>
</table>

Q	Question	Response
		We believe that, overall, CMP 251 reduces the uncertainty faced by market participants. Even if we assume that the baseline methodology ensures compliance and guarantees no adjustment or mid-year tariff changes (for the purposes of compliance with the Regulation), we still consider that uncertainty is reduced under CMP 251. This is because the removal of the risk associated with unanticipated changes to the error margin provides a significant reduction in uncertainty for both Generators and Suppliers. Short term changes to the exchange rate, on the other hand, are visible to market participants, can be protected against and are relatively small (we note that movements in the €/£ exchange rate in respect of the 2015/16 Charging Year reduce to a 1% variance when compared to the OBR forecast published just prior to the start of the Charging Year). Applicable objective (b): The principles underpinning the charging methodology, including the default proportion of revenue to be recovered from generators, are approved as meeting objective (b). Therefore, any unnecessary restrictions on how these principles are translated into charges are detrimental to meeting objective (b). The error margin included in the current methodology represents an unnecessary restriction on the underlying principles of the methodology since it applies a cap which goes above and beyond the cap stated in the regulation. By minimising the impact of compliance with 838/2010 objective (b) is better met. Applicable objective (c): The European Commission Regulation 838/2010 is legally binding for all Transmission licensees across Europe. We believe that CMP 251 ensures that National Grid remains compliant with the European legislation and properly reflects National Grid’s duties in the development of its transmission business. Whilst CMP224 also sought to ‘properly take account of developments in the transmission licensees’ transmission business’, it is sub-optimal in two respects: (1) CMP 224 goes above and beyond the cap stated in the regulation to the detriment of consumers (2) CMP 224 does not provide sufficient assurance that the regulation will not be breached The CMP 251 Original Proposal will rectify these short-comings.

Q	Question	Response
		Our assessment of options 1 and 2 presented in the consultation are that they would increase short term uncertainty for demand charges relative to the original which would be detrimental to consumers and reduce the benefits of the proposal. Given that demand charges are not the subject of the Regulation the original proposal represents the appropriate treatment for demand charges. If option 3 is legally permissible, we can see merit in considering this option further as it would reduce the short term uncertainty on Generators relative to the Original.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We are supportive of the proposed implementation approach. The approach to compliance with the Regulation should be set out at the time of publication of final charges. We do consider however that the inclusion of an error margin represents a significant distortion to the underlying principles of the charging methodology and should be remedied as soon as possible. We urge the Workgroup to progress the modification so that it can, if approved, be implemented for 2017/18 tariffs.
3	**Do you have any other comments?**	No
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No

Specific questions for CMP251

Q	Question	Response
5	**Do you have any comments on the legal opinion?**	The opinion sets out one of the 'Pros' of the current approach as: "*The way in which the Error Margin is calculated is also helpful in supporting the Current Approach. The use of the Error Margin both demonstrates a good faith attempt to mitigate the risks created by the ex-ante approach, and also (given it is based on the inaccuracies of historical forecasts) in itself represents a crude form of reconciliation.*" We consider that the legal opinion has not addressed the fact that the error margin in the current approach does not account for exchange rate risk. Whilst we understand the reasons for excluding the exchange rate in the error margin, as set out in CMP 224, we believe it is an important differentiating factor when comparing the two approaches to compliance and the legal opinion has not addressed this. Modification proposal CMP 261 has been raised just a few weeks before the end of the year. Whilst the ex-ante approach adopted for 2015/6 is fully justified as representing reasonable endeavours, this does not necessarily hold for future years as there is now clear evidence that an ex-ante approach does not ensure average generators charges are below €2.50. This may make modifications similar to CMP 261 more capable of being adopted for future years. This significantly increases the uncertainty market participants are faced with under the current methodology and challenges the '*upfront certainty*' argument made in favour of the current approach. On a general note, we don't believe it is appropriate for the Workgroup to restructure the legal opinion to fit the questions the workgroup set out as this runs the risk of misrepresenting the advice received.

Q	Question	Response
6	**Is ex ante certainty preferred over ex post accuracy?**	Generators charges for 2015/6 will be above €2.50 on average. CMP 261 has been raised, just a few weeks before the end of the 2015/16 charging year. Whilst we believe that CMP 261 is unnecessary as National Grid used reasonable to ensure compliance for 2015/6, similar modifications may be more capable of approval in future years as there is now clear evidence that an ex-ante approach does not ensure average generator charges are below €2.50. This means that the ex ante approach may not provide the 'certainty' that some members of the Workgroup seem to believe it does. CMP 251 provides both the assurance that the Regulation will be complied with and greater certainty relative to the current ex-ante approach. It is clearly preferable for all market participants to know with certainty ahead of the charging year whether or not an adjustment will take place. This allows all Parties to take appropriate steps to monitor and/or protect themselves from movements in the exchange rates and allows National Grid to keep Parties informed about the expected level of the adjustment through their periodic publication of forecasts. CMP 251 also removes the error margin and so removes the uncertainty associated with unanticipated changes to the error margin.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	Our original proposal was for the adjustment to occur '*shortly after the end of the charging year*' and reflects the principle that the adjustment should not be unreasonably delayed. Aligning the adjustment with the existing Generator reconciliation process would be consistent with this, although we do not insist on such alignment if, for instance, system constraints made this prohibitively expensive.
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	There will be trade-offs and we are comfortable with consideration of other timescales for the generation adjustment if it was deemed that other approaches were legally permissible and offered a better all round approach. For example, if delaying the adjustment until the following charging year (in line with the adjustment to demand tariffs) brought greater benefits, in terms of reduced uncertainty, then it may be appropriate to consider this.

CUSC Workgroup Consultation Response Proforma

CMP251 – Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010.

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 **29th March 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 Ryan Place at ryan.place@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:	*George Douthwaite* *George.douthwaite@npower.com* *0121 336 5322*
Company Name:	*RWE npower*
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.

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?**	No, we believe that the proposal is detrimental to facilitating CUSC objectives. The modification proposed adds new uncertainty to the TNUoS tariffs. The additional reconciliation amount is unknown at the time suppliers price customers. This will result in the need for additional risk premia to be built into 'non-pass through' customer contracts. An additional reconciliation will move costs between years so that additional revenue is recovered from a different customer base than intended. (a) We believe that the proposal CMP251 reduces competition in the energy supply or generation markets, firstly by making the cost less predictable and secondly by recovering money from a customer base different to that which existed at the time the charge arose. (b) the change makes charges less cost reflective, by moving costs to a different year and hence also different customer base. (c) the change is neutral when taking into account the developments in transmission licensees' transmission businesses. (d) the change is neutral regarding European Electricity Regulation, given the legal opinion in Annex 6 that the ex-ante approach meets the relevant European legislation at least as well as is met by the ex-post approach. *Annex 5, question 1 section 5b: "The fact that the Network Access Regulation specifically refers[18] to the right of Member States to adopt more detailed provisions than the guidelines set out in the Guidelines Regulation, and that the Network Access Regulation is silent on the use of ex-ante/ex-post (while specifically disallowing an ex-ante approach in the context of a different payment mechanism[19]), provides a solid rebuttal to any suggestion that an ex-ante approach does not comply with the relevant legislation. Similarly, ACER's opinion on the appropriate range of transmission charges paid by electricity producers is neutral as to the choice of approach.[20] ACER has clearly studied the approach taken by Member States in relation to G Charges and at no point highlights any concern with (or indeed interest in) the question of ex-ante approach versus ex-post approach."*
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We are not supportive of the modification and therefore not supportive of the implementation approach. Please also see general comments below (Q3)

Q	Question	Response
3	**Do you have any other comments?**	No implementation approach specified for an authority decision after October 2016.

Q	Question	Response
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	We do not support this modification and believe it to be unnecessary and detrimental to facilitating the CUSC objectives. However, we wish to raise a number of WG Consultation Alternative Requests for the Workgroup to consider. Alternatives 1 and 2 increase the cost of the solution, but we think this additional cost is better than the additional uncertainly. Alternative 3 offsets this additional cost, while alternatives 4 and 5 reduce the implementation cost whilst giving the best certainty to both suppliers and generators. Npower Alternative 1 This provides an additional year's notice to suppliers of this reconciliation. In the examples shown on pages 4 & 5 monies paid to or recovered from suppliers by tariff changes would be in year t+3. This additional time would help suppliers set prices for customers with more certainty. With the example quoted in section 4.9, interest is 2% + BoE base. £80m paid to generation at the start of Year t+1 becomes £84.05 in year t+2 with 2 years interest applied. This alternative would increase this cost further to £86.15m in year t+3. Npower Alternative 2. This smooths the effect of the ex-post reconciliation over several years. The advantage is that over time there should be some years of over and some of under recovery. It is hoped that by smoothing, some of these price movements would negate each other reducing the impact to customers. One third of the monies to be paid to or recovered from suppliers by tariff changes would be applied in each of years t+2, t+3 and t+4. The cost of this alternative should be the same as npower Alternative 1. Npower Alternative 3. Generation reconciliation to be delayed by a year to reduce volatility, which would allow the reconciliation to be performed as part of the normal annual reconciliation process and but at year t+2 rather than year t+1. No increase in cost over the base proposal. Npower Alternative 4 and 5. Variations of npower alternatives 1 and 2 to delay generation reconciliation in the same manner as the demand side reconciliation is proposed to be delayed. With the example quoted in section 4.9, interest is 2% + BoE base. £80m paid to generation remains £80 recovered from suppliers as the reconciliations occur at the same time, so £4.05m less cost to suppliers to pass on to customers than the original proposal.

Specific questions for CMP251

Q	Question	Response
5	**Do you have any comments on the legal opinion?**	The legal opinion suggests not only that the current (CMP224) approach as legally defendable as the proposal, but it also states the current approach is better in terms of predictability of tariffs and competitiveness within the electricity markets. Explicitly,Annex 5, question 1, section 5C states *"The use of the risk margin for forecasting error (at paragraph 14.14.5(v) of the CUSC) (**Error Margin**), and the careful weighing up of the implementation options at the time the original CUSC modification was made, demonstrate a clear desire on the part of Ofgem and NGET to implement the intent of the G Charge Guidelines and provides sound reason for avoiding an ex-post approach on grounds of the uncertainty it would create. Again, this gives robust legal argument for defending the Current Approach."* This supports our view that this proposal has no value over the current (CMP224) methodology.
6	**Is ex ante certainty preferred over ex post accuracy?**	Ex ante certainty is preferred over ex post uncertainty and volatility. We will always prefer certainty in tariffs in order to minimise risk premia that may otherwise need to be added to customers' bills.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	There should always be a minimum 12 month notice of changes to the under/over recovery of revenue through the k factor.
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	No, because the most appropriate process does not involve reconciliation.

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Respondent:	*Guy Phillips (guy.phillips@uniper.energy)*
Company Name:	*E.ON Group including 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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?**	No, whilst we think there may be scope to remove the error margin, particularly in light of the legal advice, we think that the proposed reconciliation processes under the original or any of the options assessed increase the uncertainty of tariffs and costs to TNUoS payers and further undermine the predictability of tariffs, which could be both detrimental to competition and does not improve the cost reflectivity of the current methodology.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Yes.
3	**Do you have any other comments?**	No.
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/

Specific questions for CMP251

Q	Question	Response
6	**Do you have any comments on the legal opinion?**	We would note reference to the purposive approach taken by the European Court of Justice and adopted by the Courts of England and Wales in interpreting EU Law and when assessing compliance against Regulation 838/2010. We note the conclusions that either an ex ante or ex post method could be shown to be compliant and the conclusion with respect to the current ex ante approach in paragraph 5: "the view that there is a robust argument that the Current Approach ensures compliance with the purpose of the Guidelines Regulation and therefore is not vulnerable to legal challenge by dint of taking using ex-ante calculations."
6	**Is ex ante certainty preferred over ex post accuracy?**	Yes. Although we do not think it is necessary to maintain an error margin, particularly in light of the legal advice, in our view CMP251 would add further uncertainty to the costs TNUoS payers are exposed to and undermine the predictability of tariffs.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	As quickly as practicable, whilst giving parties adequate notice of any changes in the TNUoS cost base.
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	Yes, we would not support any process that required a mid-year tariff change due to the impacts this would have on TNUoS payers. We recognise that generators would wish to be reconciled as closely as possible to the year in which the charges relate, whilst suppliers would want sufficient notice of any change in the TNUoS costs to be recovered.

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

CUSC.team@nationalgrid.com

CC: Ryan.place@nationalgrid.com

29 March 2016

Dear Ryan,

CMP251 – WORK GROUP CONSULTATION RESPONSE

Introduction

Thank you for providing the opportunity to respond to this industry consultation on the proposal *'Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010'* issued on 29 Feb 2016.

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

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

Question 1: Do you believe that CMP251 Original proposal or either of the potential options for change better facilitates the Applicable CUSC Objectives?

We consider that neither the proposal presented in CMP251 nor the potential options better facilitates CUSC Objectives. Further, we disagree that the proposal "*minimises the impact on the principles underpinning the TNUoS tariffs*" and provides predictability for suppliers and generators.

Charging objectives cited in proposal
The proposer highlights that the proposal better facilitates the following CUSC charging objective:

> *"(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);"*

Transmission licensees' costs are recovered through the charging regime. The charges reflect costs through wider locational charging and local tariffs. The proposal does not impact on the relative locational charging differences across GB or impact on local tariffs. The scope of the proposal is limited to the balance of revenue recovery between generators and suppliers. Therefore, we disagree that the proposal better facilitates this objective.

Highlands and Islands Enterprise, Fraser House, Friar's lane, Inverness, IV1 1BA
Iomairt na Gàidhealtachd 's nan Eilean, Taigh Fhriseil, Sràid nam Manach, Inbhir Nis, IV1 1BA

T +44 (0)1463 234171 E. info@hient.co.uk W www.hie.co.uk

Other charging objectives
We disagree that the proposal provides predictability for suppliers and generators. Although not referenced within the proposal, another charging objective, as defined in Section 14.14.8 of the CUSC, is to *"inform existing and potential new entrants with accurate and stable cost messages"*. It is our view that the retrospective reconciliation process discussed in CMP251 detracts from this objective as an ex post reconciliation process increases the duration of charging uncertainty – delaying the publication of final tariffs by approximately 15 months. Under the existing methodology, final tariffs are published in January ahead of the start of the charging year. Under the proposal, final tariffs would not be known until the April after the end of the charging year. Further, the reconciliation process is likely to be complex and opaque to many new and smaller market entrants.

Question 2: Is ex ante certainty preferred over ex post accuracy?

Further to above, it is our view that establishing tariffs ex ante rather than ex post provides charging certainty and stability.

The proposed method in CMP251 introduces retrospective variations in the charges which will undoubtedly undermine forward visibility of charges and hence certainty required for investment of new and existing transmission system users. This can potentially delay investment in new generation capacity and exacerbate capacity margin issues and costs to the consumer.

The proposed method introduces complex and potentially expensive reconciliation processes, in which system users will be required to have expertise in monitoring and anticipating currency exchanges in order to have forward visibility of the likely post reconciliation charges/rebates, despite an earlier CMP 224 concluding that this would be "impractical for electricity industry participants to forecast with any degree of certainty".

We agree that introducing the reconciliation process could adversely and disproportionally affect smaller market participants who are less likely to have expertise in monitoring and predicting currency exchanges.

There are other cost risks to the consumer raised by this proposal. The proposed reconciliation process taking place up to two years ex post, the financial burden of paying for any under recovery of costs will lie with National Grid Electricity Transmission plc, and hence the consumer. We support the view that additional financial costs should be avoided where possible. Further, the proposal introduces an exchange rate risk to charging tariffs – hedging against this risk will result in higher costs for consumers through higher wholesale prices and suppliers costs.

Compliance with European Commission Regulation 838/2010

One of the main drivers for CMP251 (evident from the proposal title) is to ensure CUSC compliance with European Commission Regulation 838/2010 (Part B) paragraph 3. Legal advice sought as part of the consultation exercise has clarified the position that the current methodology does in fact ensure CUSC compliance with European Commission Regulation 838/2010. Given the lack of significant legal requirement to update the charging methodology, alterations to the charging methodology for legal reasons alone is not sufficiently justified. Nonetheless, we do believe that the current method of establishing compliance (via the error margin) should be improved.

Ex-ante charging stability – HIE proposal

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

While HIE does not support the original proposal or its options, we consider that the process for determining the error margin should be improved.

Currently, the error-margin is set annually by National Grid, based on an assessment of forecast generation output (MWh) and average exchange rate in the year ahead. As discussed by the working group, both of these variables present a significant unknown that are not within the control of National Grid or reliably predictable (especially exchange rates).

We suggest that the most effective way to address the issues associated with the determination of the error margin is to remove it from the tariff process. Under the European Commission Regulation 838/2010, tariffs can legally fall within the range €0-2.5/MWh. The current methodology targets the maximum revenue recover from generators at €2.5/MWh and builds in an error margin to ensure compliance with the European regulations. We suggest that a target value should be set such that sits well within this range to mitigate the risk associated with non-compliance and remove the need for an error margin correction factor.

Setting a fixed target well within the €0-2.5/MWh range would:

- Provide charging stability for generators and suppliers
- Minimise impact on charging principles – the relative wider locational charging signals and local charging signals would be unaffected.
- Remove the need to determine an error margin as part of the tariff process
- Ensure compliance with the European regulations
- Avoid the expensive, complication and uncertainty associated with ex-post reconciliation.

We look forward to seeing the results of this consultation in due course.

Yours sincerely

P.P. Caitriona McCaig

Elaine Hanton
Joint Head of Energy

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

Highlands and Islands Enterprise, Fraser House, Friar's lane, Inverness, IV1 1BA
Iomairt na Gàidhealtachd 's nan Eilean, Taigh Fhriseil, Sràid nam Manach, Inbhir Nis, IV1 1BA

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Respondent:	*James Anderson* *james.anderson@scottishpower.com*
Company Name:	*ScottishPower Energy Management*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?**	We do not believe that the Original Proposal better facilitates the applicable CUSC objectives. By introducing an ex-post reconciliation process for generators, which would require to be reflected in their financial statements, the Proposal significantly increases uncertainty over the level of TNUoS charges to be faced and could lead to the introduction of a risk premium to the detriment of consumers. Increased uncertainty is harmful to competition and therefore the Proposal does not better facilitate applicable objective (a) than the baseline. Any change to the proportion of Allowed Revenue charged to generation and demand is reflected in the respective residual charge elements of the TNUoS tariff. The residual elements are not designed to be cost reflective and serve to achieve recovery of the stated proportions of revenue from generation and demand. As CMP251 will only impact the residual elements of TNUoS tariffs, it will have no impact on cost reflectivity and is therefore neutral against applicable objective (b). The proposal is neutral against applicable objective (c). In approving CMP244, Ofgem concluded that that modification, reflected in the current baseline would better facilitate compliance with the Electricity Regulation. The legal opinion obtained by the Workgroup concludes that “both the Current Approach and the BG Approach (CMP251) can facilitate G charges that are compliant with the Guidelines Regulation”. Therefore the Proposal does not *better* meet applicable objective (d) than the current baseline.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Although we do not support implementation of CMP251 we would support the implementation approach set out in Section 7 of the Workgroup report.

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

Specific questions for CMP251

Q	Question	Response
5	**Do you have any comments on the legal opinion?**	We concur with the legal opinion that that "both the Current Approach and the BG Approach (CMP251) can facilitate G charges that are compliant with the Guidelines Regulation". However, by reducing uncertainty ex-ante, the current approach better meets the Applicable CUSC Objectives.
6	**Is ex ante certainty preferred over ex post accuracy?**	Yes. Increased certainty in a competitive market should always lead to lower risk premia and lower costs to consumers. The legal opinion identifies no firm requirement for "ex-post accuracy" and indeed the Proposal is based upon the false premise that GB generation must be charged the full €2.50/MWh when any figure between €0/MWh and $2.50/MWh would achieve compliance with the Regulation.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	Notwithstanding our views set out at (6) above, if ex-post reconciliation was to be adopted, the process should be completed as soon as the necessary data is available for both generation and demand tariffs. Reconciling both at the same time would eliminate any cash-flow financing issues and ensure that suppliers faced the appropriate proportion of TNUoS charges in the correct Charging Year. This would also eliminate any potential discrepancies arising due to changes in market share between the Charging Year under reconciliation and the Charging Year in which supplier reconciliation is applied.
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	As reconciliation amounts relate to a specific Charging Year, any reconciliation amounts applicable to generators (under the Original Proposal) would have to be reflected in the financial statements which cover that Charging Year. An earlier reconciliation process would allow generators to include such amounts, within an acceptable level of materiality, in their financial statements.

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

Respondent:	*Garth Graham (garth.graham@sse.com)*
Company Name:	*SSE*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?**	In our view it is now clear that the baseline CUSC (with the CMP224 based solution) has failed to ensure that there is no exceedance of the €2.5MWh upper limit set in the Regulation – as witnessed by the circa €3.22/MWh level that GB generators will (based on the latest available public information) it appears, on average, be paying in the current (2015/16) charging year. In light of this fact, any practical solution which seeks to correct this will, in our view, better facilitate the Applicable CUSC Objectives; including (b) and (c) but especially (d).
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	We note the proposed implementation approach, as set out in Section 7 of the consultation document. We are also aware of the possible interaction with CMP244. Notwithstanding our comments elsewhere in the response, if CMP251 were to be approved by the Authority then, in our view, it should be implemented at the earliest possible opportunity. In particular; and noting the comments in paragraph 7.5 of the consultation document; we believe that CMP251 should be implemented at the earliest practical opportunity as there is a continuing risk that the exceedance of the €2.5MWh upper limit set in the Regulation that we have seen in this current charging year (2015/16) will continue into the next charging year (2016/17). Therefore an implementation of CMP251 such that any exceedance of the €2.5MWh upper limit in 2016/17 is reconciled in spring 2017 would be an appropriate implementation approach to be taken forward.

Q	Question	Response
3	**Do you have any other comments?**	We note (as the Proposer of CMP261) that CMP261 was raised after this CMP251 consultation document was issued. During the first CMP261 Workgroup meeting on 23rd March 2016 National Grid advised that the reconciliation arrangements that they had detailed in paragraph 4.12 of the CMP251 Workgroup consultation document was incorrect. It now appears that the charging year–end reconciliation process (for CMP251 and indeed CMP261 – if either or both are approved) would take place later in the spring than initially envisaged in the CMP251 Workgroup deliberations.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	*No.*

Specific questions for CMP251

Q	Question	Response
5	**Do you have any comments on the legal opinion?**	We note with great interest the legal opinion set out in Annex 5 and 6 of the consultation document. We are mindful that the questions posed to Addleshaw Goddard was on the basis of looking at the future rather that the existing (2015/16 charging year) situation. In that regard it should be noted that the aspects of the legal opinion with respect to an ex-ante approach assumes that it still ensures that the upper limit (of €2.5/MWh) set in the Regulation is not exceeded.

Q	Question	Response
6	**Is ex ante certainty preferred over ex post accuracy?**	If the ex-ante approach ensured that the upper limit (of €2.5/MWh) set in the Regulation is not exceeded then, in our view, this would be preferred to an ex-post approach as both approaches (ex-ante and ex-post) would ensure that there is no exceedance (of the €2.5/MWh limit) whilst an ex-ante approach would give greater certainty of the level of costs. The reason for this is that greater certainty occurs with an ex-ante approach (if it stays within the €0-2.5/MWh range) as there is no need for any reconciliation. However, if the ex-ante approach fails to ensure that the upper limit (of €2.5/MWh) set in the Regulation is not exceeded then we believe that an ex-post reconciliation is inevitable to ensure legal compliance with the Regulation.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	In our view the ex-post reconciliation process should be undertaken at the earliest practical opportunity and this should be performed without undue delay on the part of the System Operator after the end of the charging year. For the avoidance of doubt, we believe that the calculation of the two variables (£/€ exchange rate and applicable volume from 1st April to 31st March) is straightforward and that the associated credit can be paid to the affected Users shortly after the end of the charging year in question.
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	In our view it is not a question of a 'trade-off' but rather one of ensuring that any exceedance of the upper limit (of €2.5/MWh) set in the Regulation is corrected at the earliest practical opportunity. As per our answer to Question 7 above, the calculation of the amount to be reconciled is straightforward and, therefore, the payment of the associated amount to the affected Users should, equally, be straightforward. In this respect we note that the System Operator already has the contact / payment details of all the relevant parties (Generators and Demand) along with an associated robust billing system that is already capable of making credit payments to Users.

CUSC Workgroup Consultation Response Proforma

CMP251 – Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010.

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 **29th March 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 Ryan Place at ryan.place@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:	*Colin Prestwich*
Company Name:	*SmartestEnergy*
Please express your views regarding the Workgroup Consultation, including rationale. **(Please include any issues, suggestions or queries)**	We are not supportive of this proposal. We have no issues with the concept of the error margin. Introducing an additional reconciliation for generation and demand tariffs increases the risk premium that generators and suppliers will place on the tariffs forecast and will result overall in less efficient charging.

Standard Workgroup consultation questions

Q	Question	Response

Q	Question	Response
1	**Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?**	We do not believe that CMP 251 Original Proposal better facilitates any of the Applicable CUSC Objectives. 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.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	No
3	**Do you have any other comments?**	No

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

Specific questions for CMP251

Q	Question	Response
6	**Do you have any comments on the legal opinion?**	No
6	**Is ex ante certainty preferred over ex post accuracy?**	Yes. No change is preferred over change.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	We can't comment on this as we do not agree with the proposal.
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	Inevitably. We feel that introducing an additional reconciliation for generation and demand tariffs increases the risk premium that generators and suppliers will place on the tariffs forecast and will result overall in less efficient charging.

CUSC Workgroup Consultation Response Proforma

CMP251 – Removing the error margin in the cap on total TNUoS recovered by generation and introducing a new charging element to TNUoS to ensure compliance with European Commission Regulation 838/2010.

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 **29th March 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 Ryan Place at ryan.place@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:	*Mary Teuton (mteuton@vpi-i.com; 0207 312 4469)*
Company Name:	*VPI Immingham*
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.

Standard Workgroup consultation questions

Q	Question	Response
1	**Do you believe that the CMP251 Original Proposal better facilitates the Applicable CUSC Objectives?**	No, we do not believe that the proposal better facilitates the applicable CUSC objectives, (a) and (d). The current ex-ante approach complies with the relevant European Electricity Regulation and therefore the proposal does not better deliver (d). We also believe that an ex-post reconciliation would remove damage competition across generators and the requirement to factor in the risk of a forecast exchange rate error will advantage larger players over smaller players who may not have the resource to do this.
2	**Do you support the proposed implementation approach? Or are there any further implementation implications that need to be considered?**	Noting that we do not support the modification overall, should it be implemented, then we would support the proposed implementation approach.
3	**Do you have any other comments?**	We have serious concerns regarding the proposed modification. Volatility of charges is a major issue for generators, particularly smaller independents. Even having TNUoS just fixed for one year proves problematic in making investment decisions and we believe that an unforecastable ex-post reconciliation will further exacerbate this situation and prove to be a high barrier to entry. There could also be a knock on implication on security of supply if plant are forced to close as they are already operating at a less and are unable to recoup reconciliation costs.
4	**Do you wish to raise a WG Consultation Alternative Request for the Workgroup to consider?**	No, we have no further comments

Specific questions for CMP251

Q	Question	Response
6	**Do you have any comments on the legal opinion?**	We have no comments on the Legal opinion. We are of the view that the current approach complies with the EU Regulation as it states a range of generator charges from €0 to €2.5/MWh and that this is achieved with the current approach. We also agree with the Legal statement that the upfront certainty around the current ex-ante charges encourages cross border electricity trading. The use of a risk margin balances certainty against the requirement to comply with the legislation.
6	**Is ex ante certainty preferred over ex post accuracy?**	Yes, a fixed charge that provides certainty is preferred over a ex-post as it provides certainty to market participants and enables efficient trading. We would also suggest that that these "stable and accurate cost messages" as set out in Section 14 of the CUSC are important to both new entrants and independent generators. Should an element of exchange rate forecasting risk be introduced, then we believe that parties will have to start adding in a risk premium and hence the overall cost to consumers may be greater. This would be a significant disadvantage for smaller, independent who are likely to be less able to manage the risk.
7	**If an ex post reconciliation was to be adopted how quickly should the reconciliation proceed?**	If the ex-post reconciliation were to proceed, it would make sense for it to be implemented for the next charging year for which the TNUoS charges had not been set, assuming that a robust process could be implemented in the required timescales.

Q	Question	Response
8	**Are there trade-offs between speed of reconciliation and the most appropriate process?**	We can see no obvious trade off for speed of reconciliation versus the most appropriate process. We would favour a more robust process that results in accurate charges than a faster reconciliation, especially given that the current ex-ante approach complies with the EU Regulation and therefore it is unlikely that any infraction proceedings might be taking by the European Commission.

Background

The Network Access Regulation notes in its preamble that "at present, there are obstacles to the sale of electricity on equal terms, without discrimination or disadvantage in the Community. In particular, non-discriminatory network access and an equally effective level of regulatory supervision do not yet exist in each Member State, and isolated markets persist". While much of the Network Access Regulation specifically concerns itself with appropriately compensating national transmission system operators for hosting cross-border flows of electricity, the Network Access Regulation also empowers the European Commission (**Commission**) to adopt Guidelines which "determine appropriate rules leading to progressive harmonisation of the underlying principles for the setting of charges applied to producers and consumers (load) under national tariff systems […]".

Pursuant to this, the Guidelines Regulation was enacted by the European Commission on 23 September 2010. This states in its preamble that "Variations in charges faced by producers of electricity for access to the transmission system should not undermine the internal market. For this reason average charges for access to the network in Member States should be kept within a range which helps to ensure that the benefits of harmonisation are realised." Under Article 2, and Part B of the Annex, the Guidelines Regulation sets out guidelines on the level of transmission charges which each Member State may permit to be levied on electricity generators.

In the case of Great Britain, these guidelines state that annual total transmission charges paid by generators divided by the total measured energy injected annually by generators onto Great Britain's transmission system ("annual average transmission charges") shall be within a range of 0 to 2.5 Euros/MWh (**G Charge Guidelines**). (The Guidelines Regulation provides for the Agency for the Cooperation of Energy Regulators (**ACER**) to, by 1 January 2014, provide an opinion to the Commission on the appropriate range/ranges of these charges for the period after 1 January 2015. This opinion was provided by ACER on 15 April 2014 – the Commission has not yet responded.)

While the range of transmission charges are referred to as "guidelines", the Network Access Regulation requires that Member States lay down rules on effective, proportionate and dissuasive penalties for infringements of the provisions of the Network Access Regulation (Article 22).

Under Article 19 of the Network Access Regulation, Ofgem (in the context of Great Britain) is required to ensure compliance with the G Charge Guidelines. As a result, the Electricity and Gas (Internal Markets) Regulation 2011 amended the Electricity Act 1989 (**EA89**) such that Ofgem is empowered to enforce compliance (including by way of penalties) by National Grid Electricity Transmission PLC (**NGET**) with the G Charge Guidelines (Sections 25 – 27F of the EA89).

As a result of the need to implement the G Charge Guidelines, NGET raised CUSC Modification Proposal 224 in September 2013. Following a consultation, this proposal was accepted in its original form by Ofgem on 8 October 2014 and implemented as a modification to the CUSC on 22 October 2014.

Prior to the consultation the relevant provisions of the CUSC operated on the following basis (much of this remains unchanged by the modification):

- Part 2 Section 14 of the CUSC sets out the basis upon which Transmission Network Use of System charges (**TNUoS**) are calculated for any financial year (1 April to 31 March). This takes as its starting point TO Allowed Revenue (as determined under Ofgem's price control processes in conjunction with NGET's Transmission Licence) for the relevant financial year. (By way of example, for the financial year 1 April 2014 to 31 March 2015 this Maximum Allowed Revenue was set at £2,477 million.) This Maximum Allowed Revenue takes into account under or over recovery in a previous year.

- This Maximum Allowed Revenue was then split between generators and demand in a fixed proportion of generation at 27% and demand at 73%. (Applied to the example, this gives an aggregate total of £669m to be recovered from generation (**G Charge**) and £1808m to be recovered from demand.)

- The TNUoS charges paid by each generator are then calculated on a £/kW basis. This is achieved through firstly calculating location specific TNUoS charges, based upon marginal costs of investment in the transmission system as the result of increased generation in a relevant area. This, for example, might produce a charge of £25/kW for a generator located in North Scotland, with additional locational charges also applying for specific local circuits, specific types of local substation, and specific areas of offshore generation. Under the CUSC, the forecast aggregate level of these locational charges is then subtracted from the total G Charge to leave a "residual" component of the G Charge. For example, from the £669m G Charge referred to above, £326m might be taken by the aggregate locational G Charges.

- This scenario would leave a total of £343m residual G Charges to be levied on generators in the worked example. This residual amount is simply spread across the total generation capacity (based upon generating stations' Transmission Entry Capacity) to give a consistent £/kW payment for all generation capacity. So, to complete the example, the £343m residual amount would be divided by aggregate total capacity (for example, 71.5GWs) which would produce a payment of £4.81/kW for each generator in relation to the residual charge element of the G Charge.

- In this way, the aggregate annual TNUoS Charges were split between generation and demand on a 27%/73% basis.

Following the CUSC modification, the above approach has remained the same except that the 27%/73% split between generation and demand has been amended (see paragraph 14.14.5(v) of the CUSC) (**Current Approach**) such that the G Charge is set at the *lower of:*

- 27%; or

- the percentage achieved from:

  - taking the Guidelines Regulation €2.5/MWh maximum, amending this based on a risk margin for forecasting error (**Error Margin**), and multiplying this by forecast GB generation output for the relevant year (calculated two months ahead of the time) to give a total €x figure;

  - and taking this €x figure as a proportion of forecast transmission operator maximum allowed revenues (converted from pound Sterling into Euros based on forecast exchange rates, in order to ensure consistency of units),

  (**Forecasting Equation**)

  By way of example, for financial year 15/16 this has led to the generator/demand split being set at 23.2%/76.8% rather than at the 27%/73% level.

  The Error Margin is set each year by NGET based upon the level of historical error in forecast generation output and forecast transmission operator maximum allowed revenues. In its original consultation and decision on the CUSC modification, Ofgem confirm that this Error Margin is included to mitigate the risk of forecast errors causing the actual outturn average G Charges level to exceed the Guidelines Regulation €2.5/MWh maximum.

Fundamentally, this calculation is needed in the context of GB G Charges because GB G Charges are charged on a £/kW basis (power based charges) rather than on a £/kWh basis (energy based charges). Given the Guidelines Regulation sets the permitted range of G Charges on an energy basis (€/MWhs), the CUSC will always need (whether the check against the Guidelines Regulation permitted range of G Charges is conducted on an ex-ante or ex-post basis) to conduct this conversion from power to energy.

British Gas Trading Limited (**British Gas**), in its capacity as a CUSC party, made a CUSC modification proposal on 19 August 2015 (**BG Proposal**). This modification proposal suggests that the Forecasting Equation is carried out without the use of the Error Margin and (instead of relying on the Error Margin to allow for forecasting error on an ex-ante basis) an ex-post reconciliation is conducted to establish whether the Guidelines Regulation cap on G Charges has been exceeded or alternatively whether the G Charges proportion can be increased (up to a maximum of 27%) without exceeding the Guidelines Regulation cap. British Gas suggests any reconciliation would be paid by way of an adjustment to the subsequent year's G Charge/demand side charge levels.

Annex 6 – Legal Response

Legal Analysis of CUSC Modification Proposal 251 in the context of Regulation (EU) 838/2010 Compliance

In this note:

- the term "**Current Approach**" refers to the way in which Transmission Network Use of System (**TNUoS**) charges are currently calculated for any financial year (1 April to 31 March) pursuant to Part 2 of Section 14 of the CUSC;

- the term **"BG Proposal"** refers to British Gas Trading Limited's (**British Gas**'s) proposal to amend the Current Approach (as set out in CMP251); and

- the term **"G Charges"** refers to TNUoS Charges recovered from generation (as opposed to demand).

The Current Approach, the BG Proposal and the calculation of G Charges pursuant to the CUSC are outlined in more detail in the Appendix to this note.

Other defined terms used in this note are defined (**in bold in brackets**) on the first occasion on which they are used.

Introduction

This note has been prepared in order to set out our preliminary legal analysis in respect of British Gas Trading Limited's Connection and Use of System Code (**CUSC**) modification 251 (**CMP251**). The questions which this addresses are as follows:

1. Which of the Current Approach and the BG Proposal is likely to result in G Charges that are compliant with the Guidelines Regulation?

2. Where the effect of the Current Approach and/or the BG Proposal means that there is the potential for technical non-compliance with the Guidelines Regulation, what are the pros and cons of each approach, taking into account our understanding of the policy context?

The Appendix to this note sets out the background to CMP251, including a detailed summary of the *Regulation (EU) 714/2009* (**Network Access Regulation**) and *Regulation (EU) 838/2010* (**Guidelines Regulation**) requirements in relation to G Charges and the way in which the CUSC was previously modified (pursuant to CMP224) to comply with these requirements. However, to briefly summarise the position:

- The Network Access Regulation empowered the European Commission to adopt Guidelines for the progressive harmonisation of the underlying principles for the setting of charges applied to producers (generators) and consumers (load) under national tariff systems.

- Pursuant to this, the Guidelines Regulation was enacted by the European Commission on 23 September 2010. Under Article 2, and Part B of the Annex, the Guidelines Regulation sets out guidelines on the level of transmission charges which Member States may permit to be levied on electricity generators. In the case of Great Britain, these guidelines state that annual total transmission charges paid by generators divided by the total measured energy injected annually by generators onto Great Britain's transmission system ("annual average transmission charges") must be within a range of 0 to 2.5 Euros/MWh (**G Charge Guidelines**).

- As a result of the need to implement the G Charge Guidelines, NGET raised Connection and Use of System Code (**CUSC**) Modification Proposal 224 in September 2013. This modification (which was accepted by Ofgem) looked to ensure compliance with G Charge Guidelines *on an ex-ante basis.* This was achieved through amending paragraph 14.14.5 of the CUSC such that the proportion of TNUoS paid by generators is automatically reduced from the default level of 27% in circumstances where forecasts of aggregate generation, transmission operation maximum allowed revenues, and £/Euros for the relevant year suggest the G Charge Guideline Euro/MWh threshold will be exceeded.

  In recognition that the forecasts used for this calculation are likely to be inaccurate as against outturn values, an error margin is included in this calculation (based upon the level of historic error in forecast generation output and forecast transmission operator maximum allowed revenues).

- CMP251 (dated 19 August 2015) proposes that the Current Approach is amended through this error margin being removed and instead through an *ex-post* reconciliation payment being passed through from generators to demand (or vice versa) to account for differences between forecast generation/aggregate operator revenues/exchange rates and actual outturn values. The CMP251 Workgroup is currently considering this proposal.

As further set out below, our view is that both the Current Approach and the BG Approach can facilitate G Charges that are compliant with the Guidelines Regulation. Working within these two options, there are adaptations of either approach which might mean a more close alignment with the €2.5/MWh average in terms of time and/or accuracy but, as both options consistently comply, the benefits of each such adaptation would need to be weighed against the value/effort to make it.

Question 1: Which of the Current Approach and the BG Proposal is likely to result in G Charges that are compliant with the Guidelines Regulation

1. Both the Current Approach and the BG Proposal appear to facilitate G Charges that are compliant with the Guidelines Regulation.

2. This conclusion is partly driven by the fact that the European Court of Justice takes a *purposive* approach to the interpretation of EU law (an approach which has in turn been adopted by the Courts of England and Wales when they consider compliance with EU law). The result of this is that the courts will look to the broader purpose and objectives of EU legislation in interpreting the meaning of the specific provisions. In particular, the recitals setting out the objectives of the Guidelines Regulation have weight and are relevant to interpreting the requirements of the G Charge Guidelines as a whole.

3. The Guidelines Regulation is silent on whether an ex-post or ex-ante approach should be adopted in respect of G Charges, and therefore we are not of the view that the G Charge Guidelines as drafted in the Guidelines Regulation are narrowly or specifically enough drafted to preclude either an ex-ante or ex-post approach being compliant with the G Charge Guidelines. As set out in paragraphs 5 and 6 below, robust legal arguments can be made that both the Current Approach and the BG Proposal comply with the purpose and objectives of the Guidelines Regulation (and the Network Access Regulation from which

the Guidelines Regulation stems) and therefore that neither approach should be discounted on the basis of compliance/non-compliance with the G Charge Guidelines.

4. We would also note that the use of the term "annual" in the G Charge Guidelines should be read in the light of a purposive approach to interpretation of EU law and in the context of the discretion given to the Member States in deciding on more detailed provisions for the setting of G Charges. Therefore, in our view, whether a Member State calculates G Charge averages over e.g. 1 April to 31 March or 1 January to 31 December (or any other period which could reasonably be said to be "annual" and which does not interfere with purpose of the G Charge Guidelines) will not impact upon legal compliance/non-compliance with the G Charge Guidelines.

5. **Current Approach:** As you are aware, the Current Approach takes an ex-ante approach to G Charges, meaning that it could in theory lead to average G Charges exceeding the €/MWh limit set under the Guidelines Regulation. However, we are of the view that there is a robust argument that the Current Approach ensures compliance with the purpose of the Guidelines Regulation and therefore is not vulnerable to legal challenge by dint of taking using ex-ante calculations. We have reached this conclusion for the following primary reasons:

    a. The upfront certainty on G Charges and demand side TNUoS charges afforded by an ex-ante approach arguably better encourages cross-border electricity trading than an ex-post approach. While an ex-post approach guarantees the reconciliation of annual average G Charges where they exceed the G Charge Guidelines, given the overall aim of the Network Access Regulation is explicitly stated to be to encourage the cross border trading of electricity this provides argument for the Current Approach.

    b. The fact that the Network Access Regulation specifically refers[18] to the right of Member States to adopt more detailed provisions than the guidelines set out in the Guidelines Regulation, and that the Network Access Regulation is silent on the use of ex-ante/ex-post (while specifically disallowing an ex-ante approach in the context of a different payment mechanism[19]), provides a solid rebuttal to any suggestion that an ex-ante approach does not comply with the relevant legislation. Similarly, ACER's opinion on the appropriate range of transmission charges paid by electricity producers is neutral as to the choice of approach.[20] ACER has clearly studied the approach taken by Member States in relation to G Charges and at no point highlights any concern with (or indeed interest in) the question of ex-ante approach versus ex-post approach.

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[18] See Article 21 of the Network Access Regulation, which states: "This Regulation shall be without prejudice to the rights of Member States to introduce measures that contain more detailed provisions than those set out herein or in the Guidelines referred to in Article 18 [eg the G Charge Guidelines]."

[19] The Network Access Regulation specifically states (at Article 13(3)) that, *in the context of the inter-transmission system operator compensation mechanism* "Compensation payments shall be made on a regular basis with regard to a given period of time in the past. Ex-post adjustments of compensation paid shall be made where necessary, to reflect costs actually incurred."

[20] This report was produced by ACER pursuant to point 5 of Part B to the Annex of the Guidelines Regulation, and we should emphasise was neither designed to judge the validity of Member State's implementation of the Guidelines Regulation nor is it binding on the Commission in this regard.

c. The use of the risk margin for forecasting error (at paragraph 14.14.5(v) of the CUSC) (**Error Margin**), and the careful weighing up of the implementation options at the time the original CUSC modification was made, demonstrate a clear desire on the part of Ofgem and NGET to implement the intent of the G Charge Guidelines and provides sound reason for avoiding an ex-post approach on grounds of the uncertainty it would create. Again, this gives robust legal argument for defending the Current Approach.

6. **BG Proposal:** We are also of the view that the BG Proposal falls within the requirements of the Guidelines Regulation. We have reached this conclusion for the following primary reasons:

   a. As discussed in paragraph 3 above, the Guidelines Regulation does not specifically refer to a requirement to use either an ex-ante or an ex-post approach and in our view is not narrowly enough drafted to preclude either approach. Therefore, there is no explicit drafting within the Guidelines Regulation (or, for the avoidance of doubt, the Network Access Regulation) that prevents a move to an ex-post approach or necessitates the use of the ex-ante Current Approach.

   b. Similarly, we are of the view that there is a robust argument that an ex-ante approach complies with the *purpose* of the Guidelines Regulation as it clearly put in place a transparent mechanism for ensuring average G Charge levels do not exceed the levels in the G Charge Guidelines and thereby helps to ensure EU harmonisation of G Charge levels as is the stated aim of the G Charge Guidelines[21]. While the BG Proposal reduces upfront certainty for generators, we do not believe that this loss of certainty means that (from a legal perspective) the BG Proposal would fail to comply with the relevant EU legislative requirements.

   c. The ex-post mechanism through which the BG Proposal calculates average G Charges has the inherent advantage of using established figures (as opposed to forecast figures/the Error Margin) and thereby achieving a more certain and precise alignment with the G Charge Guidelines (albeit, for the reasons set out in paragraph 5 above, we are not of the view that this precise ex-post alignment is essential as a pre-requisite for legal compliance with the G Charge Guidelines).

Question 2: Where both the Current Approach and the BG Proposal has the potential to result in technical breaches, what are the pros and cons of each approach, taking into account our understanding of the policy context?

A. Pros and Cons of the Current Approach

	Pros	Cons
1.	The stated aim of the Network Access Regulation is to promote cross border exchanges of electricity. Arguably, while an ex-post approach to G Charges may guarantee more precise technical	As implicitly recognised by the use of the Error Margin, the ex-ante nature of the Current Approach means that it could lead to Generator's average G Charges exceeding the €/MWh limit set under the Guidelines Regulation. However, the approach of

[21] See the Guidelines Regulation at recital 10 and the Network Access Regulation at Article 18(2).

	Pros	Cons
	compliance with the G Charge Guidelines, the increased uncertainty on G Charge levels that an ex-post approach would introduce would (in the round) be detrimental to cross border electricity trading. When the CUSC Modification Panel originally considered how to implement the Guidelines Regulation this very uncertainty appears to have been what dissuaded them from taking forward an ex-post approach to the consultation stage. Paragraph 4.41 of the Stage 3 Final Workgroup Report[22] (**CUSC Report**) in respect of the relevant modification states, "[an ex-post reconciliation] would inject a level of uncertainty into commercial arrangements. […] This uncertainty would cause suppliers to introduce a risk premium based on the accuracy of National Grid forecasting […] it was recognised uncertainty on charges paid by GB generation in the short term had a negative impact on trading. Therefore the introduction of reconciliation could, overall, be considered counterproductive."	including the Error Margin does aim to mitigate this risk through the Error Margin being based on the level of historic error in forecast generation output and forecast transmission operator maximum allowed revenues. The error margin therefore does, in itself, represent a crude form of reconciliation. As pointed out by British Gas in its modification proposal, the use of the Error Margin does carry with it the inherent risk that the level of G Charges is set at a lower level than strictly required by the G Charge Guidelines. However, given the Error Margin is based upon historical inaccuracy of forecasting, this should inherently prevent the Error Margin from being unreasonably large.
2.	The way in which the Error Margin is calculated is also helpful in supporting the Current Approach. The use of the Error Margin both demonstrates a good faith attempt to mitigate the risks created by the ex-ante approach, and also (given it is based on the inaccuracies of historical forecasts) in itself represents a crude form of reconciliation.	

[22] Final Workgroup Report, 3 May 2014: Link

	Pros	Cons
3.	Ofgem's consultation and final decision in respect of the Current Approach carefully weighed the advantages and disadvantages of using forecasts with a long lead time to calculate the split between G Charges and demand side TNUoS charges, as against using forecasts with a short lead time. While the short lead time forecast was acknowledged as having the disadvantage of giving industry less foresight on TNUoS charges, it was ultimately selected as it reduced the potential for forecasting error which in turn meant a smaller Error Margin percentage would need to be employed .	

B. Pros and Cons of the BG Proposal

	Pros	Cons
1.	As discussed above, the Guidelines Regulation and the Network Access Regulation do not specify whether an ex-post or ex-ante approach is preferred. Therefore, there is nothing to suggest that an ex-post approach is inappropriate.	As set out in the section above on the Current Approach, good arguments have previously been made for the certainty provided by an ex-ante approach.
2.	In terms of compliance with the letter of the Guidelines Regulation, the ex-post approach guarantees that any breach of the Guidelines Regulation's ceiling on G Charges is automatically remedied, by contrast with the current approach. This represents a very transparent and easy to follow mechanism for ensuring that the level of average G Charges are precisely and robustly aligned with the requirements of the Guidelines	

	Regulation. The fact this mechanism uses ex-post figures and thereby is a more precise and robust approach to alignment has the benefit that the approach can be more easily justified as following the technical requirements of the Guidelines Regulation.	

C. Broad Conclusions

1. As set out above, we are not of the view that compliance with the Guidelines Regulation or the Network Access Regulation strictly prohibits either the use of the Current Approach or moving to the BG Proposal.

2. No doubt the Workgroup will discuss the wider advantages and disadvantages of each approach, and indeed other refinements that could be made to develop the Current Approach or the BG Proposal.

Appendix

Background

The Network Access Regulation notes in its preamble that "at present, there are obstacles to the sale of electricity on equal terms, without discrimination or disadvantage in the Community. In particular, non-discriminatory network access and an equally effective level of regulatory supervision do not yet exist in each Member State, and isolated markets persist". While much of the Network Access Regulation specifically concerns itself with appropriately compensating national transmission system operators for hosting cross-border flows of electricity, the Network Access Regulation also empowers the European Commission (**Commission**) to adopt Guidelines which "determine appropriate rules leading to progressive harmonisation of the underlying principles for the setting of charges applied to producers and consumers (load) under national tariff systems […]".

Pursuant to this, the Guidelines Regulation was enacted by the European Commission on 23 September 2010. This states in its preamble that "Variations in charges faced by producers of electricity for access to the transmission system should not undermine the internal market. For this reason average charges for access to the network in Member States should be kept within a range which helps to ensure that the benefits of harmonisation are realised." Under Article 2, and Part B of the Annex, the Guidelines Regulation sets out guidelines on the level of transmission charges which each Member State may permit to be levied on electricity generators.

In the case of Great Britain, these guidelines state that annual total transmission charges paid by generators divided by the total measured energy injected annually by generators onto Great Britain's transmission system ("annual average transmission charges") shall be within a range of 0 to 2.5 Euros/MWh (**G Charge Guidelines**). (The Guidelines Regulation provides for the Agency for the Cooperation of Energy Regulators (**ACER**) to, by 1 January 2014, provide an opinion to the Commission on the appropriate range/ranges of these charges for the period after 1 January 2015. This opinion was provided by ACER on 15 April 2014 – the Commission has not yet responded.)

While the range of transmission charges are referred to as "guidelines", the Network Access Regulation requires that Member States lay down rules on effective, proportionate and dissuasive penalties for infringements of the provisions of the Network Access Regulation (Article 22).

Under Article 19 of the Network Access Regulation, Ofgem (in the context of Great Britain) is required to ensure compliance with the G Charge Guidelines. As a result, the Electricity and Gas (Internal Markets) Regulation 2011 amended the Electricity Act 1989 (**EA89**) such that Ofgem is empowered to enforce compliance (including by way of penalties) by National Grid Electricity Transmission PLC (**NGET**) with the G Charge Guidelines (Sections 25 – 27F of the EA89).

As a result of the need to implement the G Charge Guidelines, NGET raised CUSC Modification Proposal 224 in September 2013. Following a consultation, this proposal was accepted in its original form by Ofgem on 8 October 2014 and implemented as a modification to the CUSC on 22 October 2014.

Prior to the consultation the relevant provisions of the CUSC operated on the following basis (much of this remains unchanged by the modification):

- Part 2 Section 14 of the CUSC sets out the basis upon which Transmission Network Use of System charges (**TNUoS**) are calculated for any financial year (1 April to 31 March). This takes as its starting point TO Allowed Revenue (as determined under Ofgem's price control processes in conjunction with NGET's Transmission Licence) for the relevant financial year. (By way of example, for the financial year 1 April 2014 to 31 March 2015 this Maximum Allowed Revenue was set at £2,477 million.) This Maximum Allowed Revenue takes into account under or over recovery in a previous year.
- This Maximum Allowed Revenue was then split between generators and demand in a fixed proportion of generation at 27% and demand at 73%. (Applied to the example, this gives an aggregate total of £669m to be recovered from generation (**G Charge**) and £1808m to be recovered from demand.)
- The TNUoS charges paid by each generator are then calculated on a £/kW basis. This is achieved through firstly calculating location specific TNUoS charges, based upon marginal costs of investment in the transmission system as the result of increased generation in a relevant area. This, for example, might produce a charge of £25/kW for a generator located in North Scotland,

with additional locational charges also applying for specific local circuits, specific types of local substation, and specific areas of offshore generation. Under the CUSC, the forecast aggregate level of these locational charges is then subtracted from the total G Charge to leave a "residual" component of the G Charge. For example, from the £669m G Charge referred to above, £326m might be taken by the aggregate locational G Charges.

- This scenario would leave a total of £343m residual G Charges to be levied on generators in the worked example. This residual amount is simply spread across the total generation capacity (based upon generating stations' Transmission Entry Capacity) to give a consistent £/kW payment for all generation capacity. So, to complete the example, the £343m residual amount would be divided by aggregate total capacity (for example, 71.5GWs) which would produce a payment of £4.81/kW for each generator in relation to the residual charge element of the G Charge.
- In this way, the aggregate annual TNUoS Charges were split between generation and demand on a 27%/73% basis.

Following the CUSC modification, the above approach has remained the same except that the 27%/73% split between generation and demand has been amended (see paragraph 14.14.5(v) of the CUSC) (**Current Approach**) such that the G Charge is set at the *lower of:*

- 27%; or
- the percentage achieved from:
- taking the Guidelines Regulation €2.5/MWh maximum, amending this based on a risk margin for forecasting error (**Error Margin**), and multiplying this by forecast GB generation output for the relevant year (calculated two months ahead of the time) to give a total €x figure;
- and taking this €x figure as a proportion of forecast transmission operator maximum allowed revenues (converted from pound Sterling into Euros based on forecast exchange rates, in order to ensure consistency of units),

(**Forecasting Equation**)

By way of example, for financial year 15/16 this has led to the generator/demand split being set at 23.2%/76.8% rather than at the 27%/73% level.

The Error Margin is set each year by NGET based upon the level of historical error in forecast generation output and forecast transmission operator maximum allowed revenues. In its original consultation and decision on the CUSC modification, Ofgem confirm that this Error Margin is included to mitigate the risk of forecast errors causing the actual outturn average G Charges level to exceed the Guidelines Regulation €2.5/MWh maximum.

Fundamentally, this calculation is needed in the context of GB G Charges because GB G Charges are charged on a £/kW basis (power based charges) rather than on a £/kWh basis (energy based charges). Given the Guidelines Regulation sets the permitted range of G Charges on an energy basis (€/MWhs), the CUSC will always need (whether the check against the Guidelines Regulation permitted range of G Charges is conducted on an ex-ante or ex-post basis) to conduct this conversion from power to energy.

British Gas Trading Limited (**British Gas**), in its capacity as a CUSC party, made a CUSC modification proposal on 19 August 2015 (**BG Proposal**). This modification proposal suggests that the Forecasting Equation is carried out without the use of the Error Margin and (instead of relying on the Error Margin to allow for forecasting error on an ex-ante basis) an ex-post reconciliation is conducted to establish whether the Guidelines Regulation cap on G Charges has been exceeded or alternatively whether the G Charges proportion can be increased (up to a maximum of 27%) without exceeding the Guidelines Regulation cap. British Gas suggest any reconciliation would be paid by way of an adjustment to the subsequent year's G Charge/demand side charge levels.

Annex 7 – Answers to CMP251 Workgroup Legal Questions

Legal Advice restructured to refer specifically to the questions posed by the Working Group

Restructured Legal Opinion

1 Following the discussions on the legal advice this document transposes that advice, so far as practicable, directly to the specific questions posed by the Working Group. This should be read in context of that advice note and the general position that, given the purposive interpretation, an approach that seeks to meet the principle of the guideline (which either of the proposed approaches do), rather than the specific detail as to exactly how it does it, is considered compliant and on this basis there isn't as such a "scale" of compliance at a European level which the questions are trying to establish.

2 Comments shaded in yellow are cut and paste from the legal advice directly. Comments shaded in purple are National Grid's view.

9.8 Legal Questions

3 Do the Guidelines for A Common Regulatory Approach to Transmission Charging set out in Part B of 838/2010 apply to:

(a) Calendar years only

(b) Charging years as applicable in the regulatory arrangements for each members state only i.e. regulatory years (Apr-Mar) for GB

(c) Both a. and b. (if a. and b. are different)

(d) Either a. or b. (if a. and b. are different)

(e) It is inconclusive. In which case would it equally be defensible or consistent with the legal regulatory scheme for a member state to put in place arrangements to comply with the one (a. or b.) it deemed most appropriate.

Advice Page 3, paragraph 3

We would also note that the use of the term "annual" in the G Charge Guidelines should be read in the light of a purposive approach to interpretation of EU law and in the context of the discretion given to the Member States in deciding on more detailed provisions for the setting of G Charges. Therefore, in our view, whether a Member State calculates G Charge averages over e.g. 1 April to 31 March or 1 January to 31 December (or any other period which could reasonably be said to be "annual" and which does not interfere with purpose of the G Charge Guidelines) will not impact upon legal compliance/non-compliance with the G Charge Guidelines

So in summary, looking at the questions, it is (e) on the basis that there is flexibility available at national level.

4 Does the regulation specify payment terms between producers/ generators and National Grid?

Other than the need for average charges to be within a range the regulation does not address payment terms

5 Would removing the error margin and introducing reconciliation after the year be better. Worse or neutral in terms of compliance with the regulation as compared to the baseline?

Advice Page 2 paragraph 7

(a) Both the Current Approach and the BG Proposal appear to facilitate G Charges that are compliant with the Guidelines Regulation

Advice Page 3 paragraphs 1 and 2

(b) This conclusion is partly driven by the fact that the European Court of Justice takes a *purposive* approach to the interpretation of EU law (an approach which has in turn been adopted by the Courts of England and Wales when they consider compliance with EU law). The result of this is that the courts will look to the broader purpose and objectives of EU legislation in interpreting the meaning of the specific provisions. In particular, the recitals setting out the objectives of the Guidelines Regulation have weight and are relevant to interpreting the requirements of the G Charge Guidelines as a whole.

(c) The Guidelines Regulation is silent on whether an ex-post or ex-ante approach should be adopted in respect of G Charges, and therefore we are not of the view that the G Charge Guidelines as drafted in the Guidelines Regulation are narrowly or specifically enough drafted to preclude either an ex-ante or ex-post approach being compliant with the G Charge Guidelines. As set out in paragraphs 5 and 6 below [see original], robust legal arguments can be made that both the Current Approach and the BG Proposal comply with the purpose and objectives of the Guidelines Regulation (and the Network Access Regulation from which the Guidelines Regulation stems) and therefore that neither approach should be discounted on the basis of compliance/non-compliance with the G Charge Guidelines

Advice Page 4 paragraphs 3-6

(d) We are also of the view that the BG Proposal falls within the requirements of the Guidelines Regulation. We have reached this conclusion for the following primary reasons

(e) As discussed in paragraph 3 above [see original], the Guidelines Regulation does not specifically refer to a requirement to use either an ex-ante or an ex-post approach and in our view is not narrowly enough drafted to preclude either approach. Therefore, there is no explicit drafting within the Guidelines Regulation (or, for the avoidance of doubt, the Network Access Regulation) that prevents a move to an ex-post approach or necessitates the use of the ex-ante Current Approach

(f) Similarly, we are of the view that there is a robust argument that an ex-ante approach complies with the *purpose* of the Guidelines Regulation as it clearly put in place a transparent mechanism for ensuring average G Charge levels do not exceed the levels in the G Charge Guidelines and thereby helps to ensure EU harmonisation of G Charge levels as is the stated aim of the G Charge Guidelines[23]. While the BG Proposal reduces upfront certainty for generators, we do not believe that this loss of certainty means that (from a legal perspective) the BG Proposal would fail to comply with the relevant EU legislative requirements

(g) The ex-post mechanism through which the BG Proposal calculates average G Charges has the inherent advantage of using established figures (as opposed to forecast figures/the Error Margin) and thereby achieving a more certain and precise alignment with the G Charge Guidelines (albeit, for the reasons set out in paragraph 5 above [see original], we are not of the view that this precise ex-post alignment is essential as a pre-requisite for legal compliance with the G Charge Guidelines)

So in terms of generally being compliant, removing the error margin and introducing reconciliation after the year would be neutral with the baseline. Meeting the specific range more exactly and precisely through reconciliation rather than derived from assumptions would mean a greater degree of compliance with the specific range, but within the general principles that either approach would already comply.

6 Would removing the error margin and introducing an adjustment within year be better, worse or neutral in terms of compliance with the regulation as compared to the baseline?

Advice Page 2 paragraph 7

(a) Both the Current Approach and the BG Proposal appear to facilitate G Charges that are compliant with the Guidelines Regulation

Advice Page 3 paragraphs 1 and 2

(b) This conclusion is partly driven by the fact that the European Court of Justice takes a *purposive* approach to the interpretation of EU law (an approach which has in turn been adopted by the Courts of England and Wales when they consider compliance with EU law). The result of this is that the courts will look to the broader purpose and objectives of EU legislation in interpreting the meaning of the specific provisions. In particular, the recitals setting out the objectives of the Guidelines Regulation have weight and are relevant to interpreting the requirements of the G Charge Guidelines as a whole

(c) The Guidelines Regulation is silent on whether an ex-post or ex-ante approach should be adopted in respect of G Charges, and therefore we are not of the view that the G Charge Guidelines as drafted in the Guidelines Regulation are narrowly or specifically enough drafted to preclude either an ex-ante or ex-post approach being compliant with the G Charge Guidelines. As set out in paragraphs 5 and 6 below [see original], robust legal arguments can be made that both the Current Approach and the BG Proposal comply with the purpose and objectives of the Guidelines Regulation (and the Network Access Regulation from which the Guidelines Regulation stems) and therefore that neither approach should be discounted on the basis of compliance/non-compliance with the G Charge Guidelines

[23] See the Guidelines Regulation at recital 10 and the Network Access Regulation at Article 18(2).

Advice Page 4 paragraphs 3-6

(d) We are also of the view that the BG Proposal falls within the requirements of the Guidelines Regulation. We have reached this conclusion for the following primary reasons

(e) As discussed in paragraph3, the Guidelines Regulation does not specifically refer to a requirement to use either an ex-ante or an ex-post approach and in our view is not narrowly enough drafted to preclude either approach. Therefore, there is no explicit drafting within the Guidelines Regulation (or, for the avoidance of doubt, the Network Access Regulation) that prevents a move to an ex-post approach or necessitates the use of the ex-ante Current Approach

(f) Similarly, we are of the view that there is a robust argument that an ex-ante approach complies with the *purpose* of the Guidelines Regulation as it clearly put in place a transparent mechanism for ensuring average G Charge levels do not exceed the levels in the G Charge Guidelines and thereby helps to ensure EU harmonisation of G Charge levels as is the stated aim of the G Charge Guidelines[24]. While the BG Proposal reduces upfront certainty for generators, we do not believe that this loss of certainty means that (from a legal perspective) the BG Proposal would fail to comply with the relevant EU legislative requirements

(g) The ex-post mechanism through which the BG Proposal calculates average G Charges has the inherent advantage of using established figures (as opposed to forecast figures/the Error Margin) and thereby achieving a more certain and precise alignment with the G Charge Guidelines (albeit, for the reasons set out in paragraph 5 above [see original], we are not of the view that this precise ex-post alignment is essential as a pre-requisite for legal compliance with the G Charge Guidelines)

So in terms of generally being compliant, removing the error margin and introducing an adjustment within year would be neutral with the baseline.. Meeting the specific range more exactly and precisely rather than derived from assumptions and achieving this closer to real time would mean a greater degree of compliance with the specific range, but within the general principles that either approach would already comply.

7 Is there any time limitation for any correction in respect of either a within year adjustment or after the year reconciliation taking place? If so which time limitation is preferable e.g. 30 days; 3 months; 6 months; 12 months?

Advice page 7, Broad Conclusion point 2

(a) No doubt the Workgroup will discuss the wider advantages and disadvantages of each approach, and indeed other refinements that could be made to develop the Current Approach or the BG Proposal

[24] See the Guidelines Regulation at recital 10 and the Network Access Regulation at Article 18(2).

As either approach achieves the purpose of the regulation there is no need to correct but if seeking a more specific alignment (and shortest time of potential misalignment) in terms of actual range, in principle, the sooner, the better.

8 The current arrangement sets charges based on forecast. They include an error margin to mitigate the risk of exceeding an average charge of €2.50/MWh due to forecast error. However this risk is not mitigated entirely and charges could still exceed €2.50/MWh.

(a) If this happens are charges in breach of the Regulation?

Advice Page 3, paragraphs 4-6

(i) the Current Approach takes an ex-ante approach to G Charges, meaning that it could in theory lead to average G Charges exceeding the €/MWh limit set under the Guidelines Regulation. However, we are of the view that there is a robust argument that the Current Approach ensures compliance with the purpose of the Guidelines Regulation and therefore is not vulnerable to legal challenge by dint of taking using ex-ante calculations. We have reached this conclusion for the following primary reasons

– The upfront certainty on G Charges and demand side TNUoS charges afforded by an ex-ante approach arguably better encourages cross-border electricity trading than an ex-post approach. While an ex-post approach guarantees the reconciliation of annual average G Charges where they exceed the G Charge Guidelines, given the overall aim of the Network Access Regulation is explicitly stated to be to encourage the cross border trading of electricity this provides argument for the Current Approach

– The fact that the Network Access Regulation specifically refers[25] to the right of Member States to adopt more detailed provisions than the guidelines set out in the Guidelines Regulation, and that the Network Access Regulation is silent on the use of ex-ante/ex-post (while specifically disallowing an ex-ante approach in the context of a different payment mechanism[26]), provides a solid rebuttal to any suggestion that an ex-ante approach does not comply with the relevant legislation. Similarly, ACER's opinion on the appropriate range of transmission charges paid

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[25] See Article 21 of the Network Access Regulation, which states: "This Regulation shall be without prejudice to the rights of Member States to introduce measures that contain more detailed provisions than those set out herein or in the Guidelines referred to in Article 18 [eg the G Charge Guidelines]."

[26] The Network Access Regulation specifically states (at Article 13(3)) that, *in the context of the inter-transmission system operator compensation mechanism* "Compensation payments shall be made on a regular basis with regard to a given period of time in the past. Ex-post adjustments of compensation paid shall be made where necessary, to reflect costs actually incurred."

by electricity producers is neutral as to the choice of approach.[27] ACER has clearly studied the approach taken by Member States in relation to G Charges and at no point highlights any concern with (or indeed interest in) the question of ex-ante approach versus ex-post approach

Advice Page 4 Paragraph 2

– The use of the risk margin for forecasting error (at paragraph 14.14.5(v) of the CUSC) (**Error Margin**), and the careful weighing up of the implementation options at the time the original CUSC modification was made, demonstrate a clear desire on the part of Ofgem and NGET to implement the intent of the G Charge Guidelines and provides sound reason for avoiding an ex-post approach on grounds of the uncertainty it would create. Again, this gives robust legal argument for defending the Current Approach

(b) If so, does action need to be taken to comply with the Regulation e.g. by refunding part of generation charges

(i) Action doesn't have to be taken

(c) If action has to be taken, should it be within year adjustment or after the year reconciliation or either?

(i) Action doesn't have to be taken

Annex 8 – The CMP261 Legal Response

Legal Analysis of CUSC Modification Proposal 261 in the context of Regulation (EU) 838/2010 Compliance

In this note:

- the term "**Current Approach**" refers to the way in which Transmission Network Use of System (**TNUoS**) charges are currently calculated for any financial year (1 April to 31 March) pursuant to

[27] This report was produced by ACER pursuant to point 5 of Part B to the Annex of the Guidelines Regulation, and we should emphasise was neither designed to judge the validity of Member State's implementation of the Guidelines Regulation nor is it binding on the Commission in this regard.

Part 2 of Section 14 of the CUSC;

- the term "**SSE Proposal"** refers to SSE plc's (**SSE**'s) proposal to amend the Current Approach (as set out in CMP261)

- the term **"BG Proposal"** refers to British Gas Trading Limited's (**British Gas**'s) proposal to amend the Current Approach (as set out in CMP251); and

- the term **"G Charges"** refers to TNUoS Charges recovered from generation (as opposed to demand).

The Current Approach, the BG Proposal and the calculation of G Charges pursuant to the CUSC are outlined in more detail in the Appendix to our note of 23 November 2015, which is reproduced and expanded in this note to include developments since.

Other defined terms used in this note adopt the same definitions as used in our note of 23 November 2015 or are defined (**in bold in brackets**) within the body of this note.

Introduction

This note supplements our note of the 23 November 2015 (**Previous AG Note**) and has been prepared in order to set out our preliminary legal analysis in respect of your initial legal queries following SSE's Connection and Use of System Code (**CUSC**) modification 261 (**CMP261**). The Previous AG Note set out the Guidelines Regulation, the context for it, and assessed the extent to which the Current Approach or BG Proposal better facilitated compliance with the Guidelines Regulation and, from a legal perspective, the pros and cons of each approach.

The context for CMP261 is that it has become apparent that the generation output and €/£ exchange rate forecasts which underpin the Current Approach are inaccurate in respect of the 2015/16 TNUoS charging year and that, consequently, if they are unmodified the resulting G Charges actually paid are likely to significantly exceed the cap set out in the Guidelines Regulation. The SSE Proposal therefore seeks a mid year tariff modification[28] to enable a reconciliation payment to be made in Spring 2016 to take account of G Charge overpayments made in the 2015/16 TNUoS charging year. In that context, you have asked us to address the following questions:

(i) If under the current methodology (which uses an ex-ante approach with error margin and no reconciliation) GB's average Generator charge exceeds €2.5/MWh due to forecast error for the 2015/16 Charging Year, is it compliant with the Guidelines Regulation (ie no action is required) and, if not, what action is required:

(a) reconciliation for the 2015/16 charging year;

(b) changes to the methodology to apply for future charging years?

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28 As provided for pursuant to paragraph 14.14.10 of the CUSC

(ii) If changes are required for future charging years, should they ensure we do not exceed €2.5/MWh, eg by introducing ex-post reconciliation, or would changes to reduce the risk of exceeding €2.5/MWh, eg a larger error margin, be sufficient?

(iii) If a G Charge reconciliation is required for 2015/16, how quickly should this happen?

(iv) Should the charges for Generation only Spurs be included in the calculation of the average G Charge (see CMP224 Report and Responses)?

(v) Would the use of the exchange rate at the time the Regulation was set be reasonable?

Key Conclusions

1. Our view remains that both ex-ante and ex-post reconciliation approaches can facilitate G Charges that are consistently compliant with the G Charge Guidelines.

- **The position for the 2015/16 charging year**

2. Where a forecast proves (despite the Error Margin) to have been inaccurate for a given year, and therefore takes the average G Charge above the €2.5/MWh limit, this exceeding of the Guidelines Regulation limit represents a breach of the technical requirements of the Guidelines Regulation.

3. In circumstances where the €2.5/MWh limit is *only exceeded to a minor extent* for a given charging year, we can see robust arguments that the approach still falls within the purpose of the Guidelines Regulation and therefore the legal position does not necessitate a backward looking adjustment to G Charges[29].

4. However, in circumstances where the outturn figures for a charging year demonstrate average €/MWh G Charges which are *materially above* the G Charge Guidelines limit (as is the case for the 2015/16 charging year), on balance we would suggest that the G Charges paid for the relevant year should be adjusted on a backward looking basis in order to bring them materially in line with the €2.5/MWh limit and in order to demonstrate compliance with the Guidelines Regulation.

5. The G Charges Guidelines do not mandate how such a reconciliation should be performed, and therefore the way in which (and the speed at which) such a reconciliation is performed under the CUSC[30] is a matter for wider policy and financial consideration, as opposed to the G Charge Guidelines mandating an approach. We would of course be happy to consider any specific suggestions from a legal perspective, if this would be helpful.

- **The position regarding the use of the ex-ante approach for future charging years**

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[29] As set out in the Previous AG Note (and as discussed at length during the CMP 224 process), the use of ex-post adjustment to G Charges introduces uncertainty, which in the round may be detrimental to cross border electricity trading (which is the stated aim of the Network Access Regulation). Therefore we can see that this point in particular would weigh against such an adjustment in the context of a minor incursion of the €2.5/MWh. No doubt there would be other policy and implementation considerations which would be relevant to the Working Group's decision on whether or not to reconcile in such a scenario.

[30] For example whether through the CUSC provisions at paragraph 14.14.10, an amendment to the ex-ante formula at paragraph 14.4.5 such that it factors in overpaid G Charges for the previous charging year, or through some other mechanism or amendment.

6. If it is reasonable to conclude that:

   a. the issues in 2015/16 have arisen from a unique set of circumstances (rather than a fundamental deficiency in the approach to forecasting generation output and €/£ exchange rates, in combination with the use of the Error Margin); and

   b. the Current Approach, in the round, continues to represent a reasonable and good faith method of forecasting the relevant outturn figures and thereby complying with the €2.5/MWh limit,

   we can see robust legal arguments for maintaining the current ex-ante approach going forward.

7. Given that the forecasting in respect of 2015/16 has been sufficiently far out (despite the use of the Error Margin) to result in the €2.5/MWh limit being materially exceeded, this <u>may</u> be indicative of the current approach to forecasting (or its application), in combination with the current Error Margin approach, requiring improvement (or in extremis fundamentally not being a reasonable approach to rely upon for providing robust outturn figures). This, however, is a technical question rather than a legal one.

8. In circumstances, as is the case in GB, where a tariff cannot be set up on an ex-ante basis with reasonable certainty upfront that the outturn will be compliant, industry participants, including generators, suppliers and National Grid will need to allocate the risks of that between them. However, our view is that there are no clear legal drivers that determine how to do this. Rather it is a question for the Working Group as to how best to meet the CUSC Objectives overall.

Question (i):

If under the current methodology (which uses an ex-ante approach with error margin and no reconciliation) GB's average Generator charge exceeds €2.5/MWh due to forecast error for the 2015/16 Charging Year, is it compliant with the Guidelines Regulation (ie no action is required) and, if not, what action is required:

(a) reconciliation for the 2015/16 charging year;

(b) changes to the methodology to apply for future charging years?

9. In short:

   a. there is a strong argument that a material breach of the €2.5/MWh G Charges limit in respect of the 2015/16 charging year equates to non compliance with the Guidelines Regulation;

   b. as a result, we are of the view that reconciliation of G Charges for the 2015/16 charging year would be prudent;

   c. we are not of the view that the breach in respect of the 2015/16 charging year automatically means the methodology for future charging years requires amending.

All of these points are discussed in more detail below.

- **Should there be reconciliation for the 2015/16 charging year? (Question (i)(a)):**

10. In circumstances where the outturn G Charge level for a charging year has materially exceeded the G Charges limitation in the Guidelines Regulation, we are of the view that the G Charge level for the relevant year should be reconciled on a backward looking basis. Given the wider financial and policy considerations, whether this reconciliation is by way of an amendment to the ex-ante calculations in paragraph 14.14.5[31] of the CUSC, the broad tariff update provision included at paragraph 14.14.10 of the CUSC, or through mechanisms available elsewhere in the CUSC is a question more suited to consideration by the Working Group rather than in the first instance being driven by legal tramlines.

- **Should there be changes to the methodology to apply for future charging years? (Question (i)(b)):**

11. Our understanding of the Current Approach's ex-ante formula (as set out at paragraph 14.14.5(v) of the CUSC) is that it can be characterised as aiming to mitigate the inherent risks of an ex-ante approach through (i) using robust forecasts, and (ii) using an error margin which adjusts the €2.5/MWh cap, in order to reduce the risk of a breach of the G Charge Guidelines' cap due to erroneous forecasting.

12. In our view, provided that for future charging years the ex-ante formula and the way in which the calculations are implemented continues to represent (at the time the calculation is performed) a reasonable and good faith mechanism for securing (ex-ante) compliance with the Guidelines Regulation there is a robust argument for continuing to use the Current Approach for future charging years.

13. In respect of the 2015/16 charging year, we understand the degree of error is a result of an unusual combination of factors[32]. If, however, the Current Approach proved to regularly result in G Charges that exceeded the permitted range, for example because it was clear that in ordinary circumstances the forecasting process combined with the Error Margin was not robust, then it may be right to say that a reconciliation approach whether based on the BG Proposal or SSE Proposal is better fitted to ensuring compliance with the Guidelines Regulation. However, on the basis of a single year's outturn, it is not possible to say this.

14. In circumstances, as is the case in the GB, where a tariff cannot be set upfront with reasonable confidence that the outturn will ultimately be compliant with the G Charge Guidelines, industry participants, including generators, suppliers and National Grid will need to allocate the risks of that between them. However, our view is that there are no clear legal drivers that determine how to do this. Rather it is a question for the Working Group as to how best to meet the CUSC Objectives overall.

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[31] We would note that the Error Margin (set out in definition "y" in paragraph 14.1.4.5 of the CUSC) is stated as being "based on previous years [forecasting] error […]". We understand the way in which the Error Margin is calculated cannot reasonably be characterised as having the effect of introducing a form of reconciliation in respect of a previous charging year through its adjustment of the coming year's G Charges; and instead should be characterised purely as a mechanism to assist with the Error Margin being appropriate for the coming charging year. It may be, however, that this calculation could be developed such that it does introduce a form of reconciliation into the ex-ante calculations. However, this is of course ultimately a financial point rather than a legal one.

[32] We understand unexpected weather conditions, increases in embedded generation and mis-forecasting of the exchange rate, because of volatility in the euro, have had a particular impact.

15. Our conclusion (as discussed in the Previous AG Note) that the ex ante approach is inherently capable of complying with the Guidelines Regulation is driven by a number of factors:

   a. The Guidelines Regulation itself does not set any timetable or mechanism for how and when charges should comply. As GB G Charges are set on a £/KWh basis and the Guidelines Regulation sets the permitted range of G Charges on an energy basis and in euro (€/MWhs) at the time of tariff setting, it will never be possible to be know that the outturn will fall within the permitted range and the CUSC will always need to conduct the conversion and check that average outturn over the year proves accurate. The issue is therefore not so much whether charges are compliant at a particular point in time, but when and how they are adjusted to secure compliance.

   b. As noted in our previous advice, the European Court of Justice takes a *purposive* approach to the interpretation of EU law (an approach which has in turn been adopted by the Courts of England and Wales when they consider compliance with EU law). The result of this is that the courts will look to the broader purpose and objectives of EU legislation in interpreting the meaning of the specific provisions. In particular, the recitals setting out the objectives of the Guidelines Regulation have weight and are relevant to interpreting the requirements of the G Charge Guidelines as a whole.

   c. The upfront certainty on G Charges and demand side TNUoS charges afforded by an ex-ante approach arguably better encourages cross-border electricity trading than an ex-post approach. While an ex-post approach guarantees the reconciliation of annual average G Charges where they exceed the G Charge Guidelines, given the overall aim of the Network Access Regulation is explicitly stated to be to encourage the cross border trading of electricity this provides argument for the Current Approach.

   d. The use of the risk margin for forecasting error (at paragraph 14.14.5(v) of the CUSC) (**Error Margin**), and the careful weighing up of the implementation options at the time the original CUSC modification was made, demonstrate a clear desire on the part of Ofgem and NGET to implement the intent of the G Charge Guidelines and provides sound reason for avoiding an ex-post approach on grounds of the uncertainty it would create. Again, this gives robust legal argument for defending the Current Approach, even where, on a particular occasion, the Error Margin is insufficient to prevent the average charge, at the end of a given year, from exceeding the permitted range.

Question (ii): If changes are required for future charging years, should they ensure we do not exceed €2.5/MWh, eg by introducing ex-post reconciliation, or would changes to reduce the risk of exceeding €2.5/MWh, eg a larger error margin, be sufficient?

16. As set out above, our view is that the current position does not automatically mean that the current ex ante methodology as set out in the CUSC requires amendment for future years. As discussed in the Previous AG Note, we do not view the Guidelines Regulation as mandating either an ex-ante or ex-post approach.

17. Looking to future years, the wider pros and cons in relation to an ex-post reconciliation versus an ex-ante approach continue to be key in any consideration of a move to ex-post (as was the case at the time of CMP224). Similarly, changes to the Current Approach while maintaining a wholly ex-ante methodology (eg through an increase in the Error Margin) should be considered in the light of whether the Current

Approach represents a reasonable and robust approach to securing Guidelines Regulation compliant G Charges, or whether the relevant changes are appropriate to meet this threshold.

Question (iii): If Generator charge reconciliation is required for 2015/16, how quickly should this happen?

18. The G Charge Guidelines do not mandate any timescale for such a reconciliation There will of course be wider advantages and disadvantages of each approach, including the balance of risk between industry participants and how best to achieve the CUSC Objectives, which the Working Group will no doubt consider.

Question (iv): should the charges for Generation only Spurs be included in the calculation of the average G Charge (see CMP224 Report and Responses))?

19. As was concluded during the CMP224, we would agree with the view that it is a reasonable interpretation of the Guidelines Regulation for TNUoS in respect of generation only spurs to be included within the TNUoS charges subject to the Guidelines Regulation G Charge limits (as implemented under the CUSC).

20. We say this on the basis of the wording at Part B of the Annex to the Guidelines Regulation, which refers to the Guidelines Regulation's G Charge limits applying to "total transmission tariff charges" and taking into account the exclusions (including in respect of "charges paid by produces for physical assets required for connection to the system or the upgrade of the connection") set out at paragraph 2 of the same Part B. While these terms are not given specific definitions within the Guidelines Regulation, given that generation only spurs are treated as part of the transmission system in GB and TNUoS charges include charges for the use of such spurs, we agree with the conclusions reached in respect of the CMP224 that it is reasonable that such spurs should be included within the average G charge calculation. In contrast, it is not clear on what basis the exclusion of "charges paid by produces for physical assets required for connection to the system" justifies the exclusion of TNUoS charges (as opposed to connection charges) in respect of generation only spurs, and therefore the justification for such a specific carve-out appears lacking.

Question (v): Would the use of the exchange rate at the time the Guidelines Regulation was set in 2010 be reasonable?

21. In the context of ex-ante G Charge calculations for future years, we would note that paragraph 14.14.6(v) of the CUSC refers to the forecast exchange rate calculation being calculated on the basis of "OBR Spring Forecast €/£ Exchange Rate in charging year n-1". Under the current drafting of the CUSC this would therefore be the appropriate currency forecasting basis to use for ex-ante G Charge calculations.

22. In the context of a a reconciliation of G Charges (in the context where a reconciliation is deemed appropriate) the Guidelines Regulation does not mandate a specific approach on exchange rates. However, we would suggest that a robust and reasonable approach would be to use average actual exchange rates during the period of the 2015/16 charging year.

23. By way of example, the EU Merger Regulation 139/2004/EC sets mandatory thresholds for notification in euro and the Commission's Consolidated Jurisdictional Notice made under that Regulation states that the annual turnover should be converted at the average rate for the 12 months concerned.[33] We believe that the same approach to currency conversion would be expected in this context, as it would be more consistent with the purpose of the Guidelines Regulation to use an exchange rate for the relevant year, which better represents the economic reality in that year.

Appendix

Background

The Network Access Regulation notes in its preamble that "at present, there are obstacles to the sale of electricity on equal terms, without discrimination or disadvantage in the Community. In particular, non-discriminatory network access and an equally effective level of regulatory supervision do not yet exist in each Member State, and isolated markets persist". While much of the Network Access Regulation specifically concerns itself with appropriately compensating national transmission system operators for hosting cross-border flows of electricity, the Network Access Regulation also empowers the European Commission (**Commission**) to adopt Guidelines which "determine appropriate rules leading to progressive harmonisation of the underlying principles for the setting of charges applied to producers and consumers (load) under national tariff systems […]".

Pursuant to this, the Guidelines Regulation was enacted by the European Commission on 23 September 2010. This states in its preamble that "Variations in charges faced by producers of electricity for access to the transmission system should not undermine the internal market. For this reason average charges for access to the network in Member States should be kept within a range which helps to ensure that the benefits of harmonisation are realised." Under Article 2, and Part B of the Annex, the Guidelines Regulation sets out guidelines on the level of transmission charges which each Member State may permit to be levied on electricity generators.

In the case of Great Britain, these guidelines state that annual total transmission charges paid by generators divided by the total measured energy injected annually by generators onto Great Britain's transmission system ("annual average transmission charges") shall be within a range of 0 to 2.5 Euros/MWh (**G Charge Guidelines**). (The Guidelines Regulation provides for the Agency for the Cooperation of Energy Regulators (**ACER**) to, by 1 January 2014, provide an opinion to the Commission on the appropriate range/ranges of these charges for the period after 1 January 2015. This opinion was provided by ACER on 15 April 2014 – the Commission has not yet responded.)

While the range of transmission charges are referred to as "guidelines", the Network Access Regulation requires that Member States lay down rules on effective, proportionate and dissuasive penalties for infringements of the provisions of the Network Access Regulation (Article 22).

Under Article 19 of the Network Access Regulation, Ofgem (in the context of Great Britain) is required to ensure compliance with the G Charge Guidelines. As a result, the Electricity and Gas (Internal Markets)

[33] Jurisdictional Notice, paragraph 204.

Regulation 2011 amended the Electricity Act 1989 (**EA89**) such that Ofgem is empowered to enforce compliance (including by way of penalties) by National Grid Electricity Transmission PLC (**NGET**) with the G Charge Guidelines (Sections 25 – 27F of the EA89).

As a result of the need to implement the G Charge Guidelines, NGET raised CUSC Modification Proposal 224 in September 2013. Following a consultation, this proposal was accepted in its original form by Ofgem on 8 October 2014 and implemented as a modification to the CUSC on 22 October 2014.

Prior to the consultation the relevant provisions of the CUSC operated on the following basis (much of this remains unchanged by the modification):

- Part 2 Section 14 of the CUSC sets out the basis upon which Transmission Network Use of System charges (**TNUoS**) are calculated for any financial year (1 April to 31 March). This takes as its starting point NGET's Maximum Allowed Revenue (as determined under Ofgem's price control processes in conjunction with NGET's Transmission Licence) for the relevant financial year. (By way of example, for the financial year 1 April 2014 to 31 March 2015 this Maximum Allowed Revenue was set at £2,477 million.) This Maximum Allowed Revenue takes into account under or over recovery in a previous year.

- This Maximum Allowed Revenue was then split between generators and demand in a fixed proportion of generation at 27% and demand at 73%. (Applied to the example, this gives an aggregate total of £669m to be recovered from generation (**G Charge**) and £1808m to be recovered from demand.)

- The TNUoS charges paid by each generator are then calculated on a £/kW basis. This is achieved through firstly calculating location specific TNUoS charges, based upon marginal costs of investment in the transmission system as the result of increased generation in a relevant area. This, for example, might produce a charge of £25/kW for a generator located in North Scotland, with additional locational charges also applying for specific local circuits (for example, Hartlepool at £0.53/kW), specific types of local substation, and specific areas of offshore generation. Under the CUSC, the forecast aggregate level of these locational charges is then subtracted from the total G Charge to leave a "residual" component of the G Charge. For example, from the £669m G Charge referred to above, £326m might be taken by the aggregate locational G Charges.

- This scenario would leave a total of £343m residual G Charges to be levied on generators in the worked example. This residual amount is simply spread across the total generation capacity (based upon generating stations' Transmission Entry Capacity) to give a consistent £/kW payment for all generation capacity. So, to complete the example, the £343m residual amount would be divided by aggregate total capacity (for example, 71.5GWs) which would produce a payment of £4.81/kW for each generator in relation to the residual charge element of the G Charge.

- In this way, the aggregate annual TNUoS Charges were split between generation and demand on a 27%/73% basis.

Following the CUSC modification, the above approach has remained the same except that the 27%/73% split between generation and demand has been amended (see paragraph 14.14.5(v) of the CUSC) (**Current Approach**) such that the G Charge is set at the *lower of:*

- 27%; or

- the percentage achieved from:

    - taking the Guidelines Regulation €2.5/MWh maximum, amending this based on a risk margin for forecasting error (**Error Margin**), and multiplying this by forecast GB generation output for the relevant year (calculated two months ahead of the time) to give a total €x figure;

- and taking this €x figure as a proportion of forecast transmission operator maximum allowed revenues (converted from pound Sterling into Euros based on forecast exchange rates, in order to ensure consistency of units),

(**Forecasting Equation**)

By way of example, for financial year 15/16 this has led to the generator/demand split being set at 23.2%/76.8% rather than at the 27%/73% level.

The Error Margin is set each year by NGET based upon the level of historical error in forecast generation output and forecast transmission operator maximum allowed revenues. In its original consultation and decision on the CUSC modification, Ofgem confirm that this Error Margin is included to mitigate the risk of forecast errors causing the actual outturn average G Charges level to exceed the Guidelines Regulation €2.5/MWh maximum.

Fundamentally, this calculation is needed in the context of GB G Charges because GB G Charges are charged on a £/kW basis (power based charges) rather than on a £/kWh basis (energy based charges). Given the Guidelines Regulation sets the permitted range of G Charges on an energy basis (€/MWhs), the CUSC will always need (whether the check against the Guidelines Regulation permitted range of G Charges is conducted on an ex-ante or ex-post basis) to conduct this conversion from power to energy.

British Gas Trading Limited (**British Gas**), in its capacity as a CUSC party, made a CUSC modification proposal on 19 August 2015 (**BG Proposal**). This modification proposal suggests that the Forecasting Equation is carried out without the use of the Error Margin and (instead of relying on the Error Margin to allow for forecasting error on an ex-ante basis) an ex-post reconciliation is conducted to establish whether the Guidelines Regulation cap on G Charges has been exceeded or alternatively whether the G Charges proportion can be increased (up to a maximum of 27%) without exceeding the Guidelines Regulation cap. British Gas suggest any reconciliation would be paid by way of an adjustment to the subsequent year's G Charge/demand side charge levels. That proposal remains under consideration. As part of its work, the CMP251 Working Group Consultation (dated 29 February 2016) looked at 3 reconciliation options, including Option 1, an ex-post reconciliation in Spring 2016 whereby each generator would receive a credit for overpayment over the charging year, with recovery from suppliers over the following charging year..

SSE, also in its capacity as a CUSC party made a further CUSC modification proposal on 8 March 2016 (**SSE Proposal**). This proposal observes that for a number of reasons, the forecasts which underpin the Current Approach to generation transmission charges are proving inaccurate and if not corrected, the actual outturn average G Charges level are currently likely to substantially exceed the permitted maximum charge of €2.5/MWh for the charging year 2015/16. SSE are therefore proposing a mid-year tariff change, to achieve an ex-post reconciliation for the current charging year, seeking to apply "Option 1" of the methodologies considered in the CMP251 Working Group Consultation i.e. reconciliation payments to generators in Spring 2016 and recovery of such payments from suppliers during the charging year 2017/16.

Annex 9 – Exchange Rate Risk Analysis

Year	Limit €/MWh	Error Margin	Adjusted Limit €/MWh	Energy Forecast TWh	AR £m	ER €/£	G	D	G Rev	D Rev	G Res £/KW	D Res £/KW	G Charging base £/KW	Demand Peak GW	HH Charge Base GW	NHH Demand TWh
2015/16	2.5	6.4%	2.34	319.6	2637	1.22	23.2%	76.8%	613.0	2024	4.81	35.63	71.5	52.4	15	27.4
2016/17	2.5	8.2%	2.30	268.7	2709	1.36	16.7%	83.3%	453.4	2255	0.51	45.33	62.9	49.8	13.1	26.1

Ex Ante 2015/16

2015/16	2.5	6.4%	2.34	319.6	2638	1.22	23.2%	76.8%	613.0	2025	4.81	35.63

Ex Post Tariff at t-2m   Impact of removal of risk margin

												HH £/KW	NHH p/KWh
2015/16	2.5	0.0%	2.5	319.6	2638	1.22	24.8%	75.2%	654.9	1983	5.40	34.83	
									42	-42	0.59	-0.80	-0.11

Reconciliation   Impact of exchange rate risk only

												HH £/KW	NHH p/KWh	
2015/16	2.5	0.0%	2.5	319.6	2638	1.39	21.8%	78.2%	574.8	2063	4.28	36.36		£6.36m cost of carry of £81m
									-80.1	80.4	-1.12	1.53	0.21	

Ex Ante 2016/17

2016/17	2.5	8.2%	2.30	268.7	2709	1.36	16.7%	83.3%	453.4	2256	0.51	45.33

Ex Post Tariff at t-2m   Impact of removal of risk margin

												HH £/KW	NHH p/KWh
2016/17	2.5	0.0%	2.5	268.7	2709	1.36	18.2%	81.8%	493.9	2215	1.15	44.52	
									41	-41	0.64	-0.81	-0.11

Reconciliation   Impact of exchange rate risk only Scenaio (a)

												HH £/KW	NHH p/KWh	
2016/17	2.5	0.0%	2.5	268.7	2709	1.19	20.8%	79.2%	564.5	2145	2.28	43.10		No cost of carry as NG in surplu:
									70.6	-70.6	1.12	-1.42	-0.20	

Reconciliation   Impact of exchange rate risk only Scenaio (b)

												HH £/KW	NHH p/KWh	
2016/17	2.5	0.0%	2.5	268.7	2709	1.53	16.2%	83.8%	439.1	2270	0.28	45.62		£4.37m cost of carry of -54.9
									-54.9	54.9	-0.84	2.52	0.15	

Annex 10 – The Swedish Approach to the G:D Split

An alternative method to apply to EU Regulation 838/2010

Background

9 Like GB, Sweden applies power-based capacity charges to generation and is also required to comply with EU Regulation 838/2010[34]. Svenska Kraftnat recovers 39% of its allowed revenue from generation and is required to ensure that the value of the annual average transmission charges paid by producers is within a range of €0-1.2/MWh. Regulation 838/2010 provides latitude to Member States in the detailed approach taken, and in the context of CMP251 it makes sense to consider how countries with similar generation charging regimes compare.

10 Sweden also uses an ex ante approach to determine its G:D split, but it does not use an error margin in its calculation. This approach should therefore be of particular interest given the identification of the "error margin" as the defect in CMP251.

Calculations compared

11 Sweden takes a different approach to the power to energy calculation (converting charges based on MW to MWh, the unit on which the Euro cap is defined). In GB, the power to energy calculation is made by applying a demand forecast to the TO Revenue to arrive at the £/MWh value. The variations around the demand and generation revenue forecasts are the reasons for including an error margin.

12 Sweden takes its contracted generation and multiplies this capacity by a standardised utilisation as a proxy for demand. It applies a standardised "base case" for how many hours each MW of energy is used, and that standard is taken from the ENTSO-E's annual Tariff Overview Report[35]. The report identifies 5000 hours as the central base case. In other words, the Swedes make the assumption that each MW of capacity on the transmission network is used for 5000 hours. By using its contracted generation position, it also removes the generation revenue uncertainty.

13 A calculation is performed below applying the Swedish methodology to GB for the year 2015/16.

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[34] Ireland is the only other European country with capacity-based G charges

[35] https://www.entsoe.eu/publications/market-reports/transmission-tariffs/Pages/default.aspx

2015/16	Sweden/ SEK	GB/ £
AR		£ 2,644,700,000
		27%
G Rev	816,000,000	714,069,000
Capacity (MW)	20,800	69,646
Usage (h)	5,000	5,000
Energy (MWh)	104,000,000	348,230,000
G Charge	7.85	2.05
ER	0.11	1.4
€/MWh	0.86	2.87
Cap (€/MWh)	1.2	2.5
		2.50
Split		**23.5%**

14 Clearly, using 5000 hours as a proxy for average utilisation in GB may not be appropriate as this is significantly higher than the average in this country, though appropriate for Sweden. However, it might be possible to build on this methodology to derive an appropriate average utilisation for GB which could be applied in the calculation, and negate the need for an error margin.

15 For example, using a Load Factor proxy for utilisation more akin to what might be expected in GB[36], the following calculation could be made:

2015/16	GB	
AR	£ 2,644,700,001	
	27%	
G Rev	714,069,000	
Capacity (MW)	69,646	
Usage (h)	3,989	2014/15
Energy (MWh)	277,817,894	
G Charge	2.57	
ER	1.4	
€/MWh	3.60	
Cap (€/MWh)	2.5	
	2.49	
Split	18.7%	

[36] The last complete year of data that we have (2014/15) using the sum of max(metered output, FPN, or 0) for each settlement period for each station for every day of the year divided by 2 and multiplied by TEC gives a utilisation of 3989 hours.

It can be seen therefore that ex ante approaches without using error margins are possible, if a methodology to identify average usage can be agreed.

Original

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.1 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.2 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.3 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)**".

14.14.4 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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

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

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

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

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

v.) The application of a Transmission Network Use of System Revenue split between generation and demand (the "G:D Split") where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{Cap_{EC} * GO}{MAR * ER}$$

Where;

Cap_{EC} = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation

~~y = Error margin built in to adjust~~ $\cancel{Cap_{EC}}$ ~~to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n

MAR = ~~Forecast~~ TO Maximum Allowed Revenue (£) for charging year n

ER = ~~OBR Spring Forecast~~ €/£ Exchange Rate in charging year n~~-1~~

vi.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

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

14.14.6 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.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.7 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.8 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.9 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.10 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and

Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.11 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.12 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.13 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.14 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. Adjustment of Generator Charges: On or before the end of May, The Company shall prepare and send to each User a statement showing the annual Generation Charges paid by that User in charging year n against the Generation Charges payable with the adjusted G:D split. In relation to any sum shown in this statement as being due to the User The Company shall make a one off payment to the User for this and in relation to any sum shown in this statement as being due to The Company shall issue an invoice to the User payable within 30 days.

ii. Adjustment to the demand TNUoS tariffs: the demand TNUoS tariffs for charging year n+2 shall be adjusted to reflect the reconciliation of generator charges made or received in charging year y+1 in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2.

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a) **The Residual Tariff**

14.15.132 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{p(TRR - GDSadj_{t-2}) - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

GDSadj = The under or over recovery which relates to the G:D Split adjustment to ensure compliance with European Regulation 838/2010. The value of $GDSadj_{t-2}$ is the sum of the rebate or charges made to generators described in paragraph 14.14.5. The $GDSadj_{t-2}$ will be positive where a rebate has been made to generators in t-1 and negative where a charge has been made to generators in t-1.

WACM1

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.5 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.6 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.7 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.8 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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

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

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

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

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

xii.) The application of a Transmission Network Use of System Revenue split between generation and demand (the "G:D Split") where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{Cap_{EC} * GO}{MAR * ER}$$

Where;

Cap_{EC} = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation

~~y = Error margin built in to adjust~~ $\cancel{Cap_{EC}}$ ~~to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n

MAR = ~~Forecast~~ TO Maximum Allowed Revenue (£) for charging year n

ER = ~~OBR Spring Forecast~~ €/£ Exchange Rate in charging year n~~-1~~

xiii.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

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

14.14.16 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.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.17 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.18 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.19 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.20 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.21 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.22 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.23 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.24 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. Adjustment of Generator Charges: Where CAP_{ec} has been exceeded, the generation TNUoS tariffs for charging year y+2 shall be adjusted to reflect the reconciliation of generator charges in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2.

ii. Adjustment to the demand TNUoS tariffs: the demand TNUoS tariffs for charging year y+2 shall be adjusted to reflect the reconciliation of generator charges in respect of charging year

y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2.

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b) **The Residual Tariff**

14.15.133 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{p(TRR - GDSadj_{t-2}) - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RTG = \frac{[(1-p) \times TRR + GDSadj_{t-2}] - TRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

GDSadj = Where CAP_{EC} has been exceeded, the amount which relates to the G:D Split adjustment to ensure compliance with European Regulation 838/2010. The value of $GDSadj_{t-2}$ is the value of the reconciliation described in paragraph 14.14.5.

WACM2.

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.9 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.10 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.11 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.12 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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

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

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

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

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

xix.) The application of a Transmission Network Use of System Revenue split between generation and demand (the "G:D Split") where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{Cap_{EC} * GO}{MAR * ER}$$

Where;

Cap_{EC} = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation

~~y = Error margin built in to adjust~~ $\cancel{Cap_{EC}}$ ~~to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n

MAR = ~~Forecast~~ TO Maximum Allowed Revenue (£) for charging year n

ER = ~~OBR Spring Forecast~~ €/£ Exchange Rate in charging year n~~-1~~

xx.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

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

14.14.26 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.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.27 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.28 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.29 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.30 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.31 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;

- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and

- be implementable within practical cost parameters and time-scales.

14.14.32 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.33 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.34 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. Adjustment of Generator Charges: On or before the end of May, The Company shall prepare and send to each User a statement showing the annual Generation Charges paid by that User in charging year n against the Generation Charges payable with the adjusted G:D split. In relation to any sum shown in this statement as being due to the User The Company shall make a one off payment to the User for this and in relation to any sum shown in this statement as being due to The Company shall issue an invoice to the User payable within 30 days.

ii. Adjustment to the demand TNUoS tariffs: the demand TNUoS tariffs for charging years y+2, y+3 and y+4 shall be adjusted by equal amounts to reflect the Generator Reconciliation Payment made or received in charging year y+1 in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2, y+3 and y+4.

c) **The Residual Tariff**

14.15.134 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{p(TRR - GDSadj_{t-2}) - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p)\times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT	=	Residual Tariff (£/MW)
p	=	Proportion of revenue to be recovered from demand
GDSadj	=	The under or over recovery which relates to the G:D Split adjustment to ensure compliance with European Regulation 838/2010. The value of $GDSadj_{t-2}$ is the sum of the rebate or charges made to generators described in paragraph 14.14.5 divided by three, plus any relevant thirds related to the same rebate or charges made in t-3 and t-4.

WACM3.

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.13 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.14 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

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14.14.40 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.41 In setting and reviewing these charges The Company has a number of further objectives. These are to:

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- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
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14.14.43 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.44 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. The generation TNUoS tariffs for charging years y+2, y+3 and y+4 shall be adjusted by equal amounts to reflect the correct G:D Split in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2, y+3 and y+4.

ii. Adjustment to the demand TNUoS tariffs: the demand TNUoS tariffs for charging years y+2, y+3 and y+4 shall be adjusted by equal amounts to reflect the Generator Reconciliation Payment made or received in charging year y+1 in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2, y+3 and y+4.

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d) **The Residual Tariff**

14.15.135 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak

Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{p(TRR - GDSadj_{t-2}) - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RTG = \frac{[(1-p) \times TRR + GDSadj_{t-2}] - TRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

GDSadj = The under or over recovery which relates to the G:D Split adjustment to ensure compliance with European Regulation 838/2010. The value of $GDSadj_{t-2}$ is the value of x as set out in paragraph 14.14.5 divided by 3 plus any relevant thirds related to the same in t-3 and t-4.

WACM4.

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.17 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.18 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of

System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.19 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.20 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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

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

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

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

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

xxxiii.) The application of a Transmission Network Use of System Revenue split between generation and demand (the "G:D Split") where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{Cap_{EC} * GO}{MAR * ER}$$

Where;

Cap_{EC} = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation

~~y = Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n

MAR = ~~Forecast~~ TO Maximum Allowed Revenue (£) for charging year n

ER = ~~OBR Spring Forecast~~ €/£ Exchange Rate in charging year n~~-1~~

xxxiv.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

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

14.14.46 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.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.47 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.48 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.49 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.50 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.51 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.52 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.53 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.54 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. Reconciliation of Generator Charges: The Company shall prepare and send to each User a statement showing the annual Generation Charges paid by that User in charging year n against the Generation Charges payable with the adjusted generation TNUoS tariffs. In relation to any sum shown in this statement as being due to the User The Company shall make a one off payment to the User for this.

ii. Reconciliation of the demand TNUoS tariffs: The Company shall prepare and send to each User a statement showing the annual Demand Charges paid by that User in charging year n against the Demand Charges payable with the adjusted demand TNUoS tariffs. In relation to any sum shown in this statement as being due to The Company shall issue an invoice to the User.

WACM5.

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.21 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.22 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.23 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.24 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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

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

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

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

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

xl.) The application of a Transmission Network Use of System Revenue split between generation and demand (the "G:D Split") where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{Cap_{EC} * GO}{MAR * ER}$$

Where;

Cap_{EC} = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation

~~y = Error margin built in to adjust~~ $\cancel{Cap_{EC}}$ ~~to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n

MAR = ~~Forecast~~ TO Maximum Allowed Revenue (£) for charging year n

ER = ~~OBR Spring Forecast~~ €/£ Exchange Rate in charging year n~~-1~~

xli.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

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

14.14.56 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.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.57 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.58 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.59 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.60 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.61 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;

- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and

- be implementable within practical cost parameters and time-scales.

14.14.62 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.63 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.64 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. Adjustment of Generator Charges: Where CAP_{EC} is exceeded, on or before the end of May, The Company shall prepare and send to each User a statement showing the annual Generation Charges paid by that User in charging year n against the Generation Charges payable with the adjusted G:D split. In relation to any sum shown in this statement as being due to the User The Company shall make a one off payment to the User for this.

ii. Adjustment to the demand TNUoS tariffs: the demand TNUoS tariffs for charging year n+2 shall be adjusted to reflect the reconciliation of generator charges made or received in charging year y+1 in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2.

e) **The Residual Tariff**

14.15.136 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{p(TRR - GDSadj_{t-2}) - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RT_G = \frac{[(1-p) \times TRR] - ITRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

GDSadj = The under recovery which relates to the G:D Split adjustment to ensure compliance with European Regulation 838/2010. The value of $GDSadj_{t-2}$ is the sum of the rebate made to generators described in paragraph 14.14.5.

WACM6.

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.25 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.26 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.27 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.28 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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

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

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

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

xlvii.) The application of a Transmission Network Use of System Revenue split between generation and demand (the "G:D Split") where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{Cap_{EC} * GO}{MAR * ER}$$

Where;

Cap_{EC} = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation

~~y = Error margin built in to adjust~~ ~~Cap_{EC}~~ ~~to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n

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xlviii.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

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

14.14.66 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.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

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14.14.68 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.69 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.70 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.71 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.72 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.73 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.74 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. Adjustment of Generator Charges: the generation TNUoS tariffs for charging year y+2 shall be adjusted to reflect the reconciliation of generator charges in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2.

ii. Adjustment to the demand TNUoS tariffs: the demand TNUoS tariffs for charging year y+2 shall be adjusted to reflect the reconciliation of generator charges in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2.

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f) **The Residual Tariff**

14.15.137 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{p(TRR - GDSadj_{t-2}) - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RTG = \frac{[(1-p) \times TRR + GDSadj_{t-2}] - TRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

GDSadj = The under or over recovery which relates to the G:D Split adjustment to ensure compliance with European Regulation 838/2010. The value of $GDSadj_{t-2}$ is the value of the reconciliation described in paragraph 14.14.5.

<u>WACM7.</u>

Part 2 - The Statement of the Use of System Charging Methodology

Section 1 – The Statement of the Transmission Use of System Charging Methodology

14.14 Principles

14.14.29 Transmission Network Use of System charges reflect the cost of installing, operating and maintaining the transmission system for the Transmission Owner (TO) Activity function of the Transmission Businesses of each Transmission Licensee. These activities are undertaken to the standards prescribed by the Transmission Licences, to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

14.14.30 A Maximum Allowed Revenue (MAR) defined for these activities and those associated with pre-vesting connections is set by the Authority at the time of the Transmission Owners' price control review for the succeeding price control period. Transmission Network Use of System Charges are set to recover the Maximum Allowed Revenue as set by the Price Control (where necessary, allowing for any K_t adjustment for under or over recovery in a previous year net of the income recovered through pre-vesting connection charges).

14.14.31 The basis of charging to recover the allowed revenue is the Investment Cost Related Pricing (ICRP) methodology, which was initially introduced by The Company in 1993/94 for England and Wales. The principles and methods underlying the ICRP methodology were set out in the The Company document "**Transmission Use of System Charges Review: Proposed Investment Cost Related Pricing for Use of System (30 June 1992)"**.

14.14.32 In December 2003, The Company published the Initial Thoughts consultation for a GB methodology using the England and Wales methodology as the basis for consultation. The Initial Methodologies consultation published by The Company in May 2004 proposed two options for a GB charging methodology with a Final Methodologies consultation published in August 2004 detailing The Company's response to the Industry with a recommendation for the GB charging methodology. In December 2004, The Company published a Revised Proposals consultation in response to the Authority's invitation for further review on certain areas in The Company's recommended GB charging methodology.

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

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

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

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

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

Iiv.) The application of a Transmission Network Use of System Revenue split between generation and demand (the "G:D Split") where the proportion of the total revenue paid by generation, for the purposes of tariff setting, is the lower of 0.27 or x times the total revenue, where x for a charging year n is calculated as:

$$x_n = \frac{Cap_{EC} * GO}{MAR * ER}$$

Where;

Cap_{EC} = Upper limit of the range specified by European Commission Regulation 838/2010 Part B paragraph 3 (or any subsequent regulation specifying such a limit) on annual average transmission charge payable by generation

~~y = Error margin built in to adjust Cap_{EC} to account for difference in one year ahead forecast and outturn values for MAR and GO, based on previous years error at the time of calculating the error for charging year n~~

GO = Forecast GB Generation Output for generation liable for Transmission charges (i.e. energy injected into the transmission network in MWh) for charging year n

MAR = ~~Forecast~~ TO Maximum Allowed Revenue (£) for charging year n

ER = ~~OBR Spring Forecast~~ €/£ Exchange Rate in charging year n~~-1~~

lv.) The number of generation zones using the criteria outlined in paragraph 14.15.42 has been determined as 21.

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

14.14.76 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.

The Transmission Licence requires The Company to operate the National Electricity Transmission System to specified standards. In addition The Company with other transmission licensees are required to plan and develop the National Electricity Transmission System to meet these standards. These requirements mean that the system must conform to a particular Security Standard and capital investment requirements are largely driven by the need to conform to both the deterministic and supporting cost benefit analysis aspects of this standard. It is this obligation, which provides the underlying rationale for the ICRP approach, i.e. for any changes in generation and demand on the system, The Company must ensure that it satisfies the requirements of the Security Standard.

14.14.77 The Security Standard identifies requirements on the capacity of component sections of the system given the expected generation and demand at each node, such that demand can be met and generators' output over the course of a year (capped at their Transmission Entry Capacity, TEC) can be accommodated in the most economic and efficient manner. The derivation of the incremental investment costs at different points on the system is therefore determined against the requirements of the system both at the time of peak demand and across the remainder of the year. The Security Standard uses a Demand Security Criterion and an Economy Criterion to assess capacity requirements. The charging methodology therefore recognises both these elements in its rationale.

14.14.78 The Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard, whilst the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently. The latter is achieved through a set of deterministic parameters that have been derived from a generic Cost Benefit Analysis (CBA) seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.

14.14.79 The TNUoS charging methodology seeks to reflect these arrangements through the use of dual backgrounds in the Transport Model, namely a Peak Security background representative of the Demand Security Criterion and a Year Round background representative of the Economy Criterion.

14.14.80 To recognise that various types of generation will have a different impact on incremental investment costs the charging methodology uses a generator's TEC, Peak Security flag, and Annual Load Factor (ALF) when determining Transmission Network Use of System charges relating to the Peak Security and Year Round backgrounds respectively. For the Year Round background the diversity of the plant mix (i.e the proportion of low carbon and carbon generation) in each charging zone is also taken into account.

14.14.81 In setting and reviewing these charges The Company has a number of further objectives. These are to:

- offer clarity of principles and transparency of the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- charge on the basis of services provided and on the basis of incremental rather than average costs, and so promote the optimal use of and investment in the transmission system; and
- be implementable within practical cost parameters and time-scales.

14.14.82 Condition C13 of The Company's Transmission Licence governs the adjustment to Use of System charges for small generators. Under the condition, The Company is required to reduce TNUoS charges paid by eligible small generators by a designated sum, which will be determined by the Authority. The licence condition describes an adjustment to generator charges for eligible plant, and a consequential change to demand charges to recover any shortfall in revenue. The mechanism for recovery will ensure revenue neutrality over the lifetime of its operation although it does allow for effective under or over recovery within any year. For the avoidance of doubt, Condition C13 does not form part of the Use of System Charging Methodology.

14.14.83 The Company will typically calculate TNUoS tariffs annually, publishing final tariffs in respect of a Financial Year by the end of the preceding January. However The Company may update the tariffs part way through a Financial Year.

14.14.84 Forecast and reconciliation of x in the Transmission Network Use of System Revenue Split between Generation and Demand ("the G:D Split")

In setting the G:D split, at paragraph 14.14.5(v), for charging year n, x shall be calculated on a forecast of "GO" and "MAR" and "ER" shall be the OBR Spring Forecast €/£ Exchange Rate.

In each Financial Year (charging year y+1) on or before the end of May, The Company shall recalculate the G:D Split for the previous Financial Year (charging year y) in accordance with paragraph 14.14.5(v) and:

i. Adjustment of Generator Charges: On or before the end of May, The Company shall prepare and send to each User a statement showing the annual Generation Charges paid by that User in charging year y against the Generation Charges payable with the adjusted G:D split. In relation to any sum shown in this statement as being due to the User The Company shall make a one off payment to the User for this. In relation to any sum shown in this statement as being due to The Company an adjustment shall be made to Generator TNUoS tariffs for charging year y+2 as outlined in paragraph 14.15.133.

ii. Adjustment to the demand TNUoS tariffs: the demand TNUoS tariffs for charging year n+2 shall be adjusted to reflect the reconciliation of generator charges made or received in charging year y+1 in respect of charging year y. The Company will notify market participants of this change in revenue with the TNUoS forecast following charge setting in y+1 for Charging Year y+2.

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g) **The Residual Tariff**

14.15.138 As a result of the factors above, in order to ensure adequate revenue recovery, a constant non-locational **Residual Tariff** for generation and demand is calculated, which includes infrastructure substation asset costs. It is added to the initial transport tariffs for both Peak Security and Year Round backgrounds so that the correct generation / demand revenue split is maintained and the total revenue recovery is achieved.

$$RT_D = \frac{p(TRR - GDSadj_{t-2}) - ITRR_{DPS} - ITRR_{DYR}}{\sum_{Di=1}^{14} D_{Di}}$$

$$RTG = \frac{[(1-p)\times TRR\ ] - TRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$

Where

RT = Residual Tariff (£/MW)

p = Proportion of revenue to be recovered from demand

GDSadj = The under or over recovery which relates to the G:D Split adjustment to ensure compliance with European Regulation 838/2010. The value of $GDSadj_{t-2}$ is the sum of the rebate or charges made to generators described in paragraph 14.14.5. The $GDSadj_{t-2}$ will be positive where a rebate has been made to generators in t-1 and negative where a charge has been made to generators in t-1.

14.15.139 Where the under recovery relating to the generator G:D Split adjustment referred to in paragraph 14.14.5 requires adjustment to the generation Residual Tariff, the following formula will apply instead of the RTG equation in 14.15.132.

$$RTG = \frac{[(1-p)\times TRR + GDSadj_{t-2}] - TRR_{GPS} - ITRR_{GYRNS} - ITRR_{GYRS} - LCRR_G}{\sum_{Gi=1}^{n} G_{Gi}}$$