Stage 02: Workgroup Consultation	At what stage is this document in the process?

CMP287: 'Improving TNUoS Predictability Through Increased Notice of Inputs Used in the TNUoS Tariff Setting Process'.

01	Proposal form
02	Workgroup Consultation
03	Workgroup Report
04	Code Administrator Consultation
05	Draft CUSC Modification
06	Final CUSC Modification Report

Purpose of Modification: CMP287 seeks to improve the predictability of TNUoS demand charges by bringing forward the date at which certain parameters used in TNUoS tariff setting (such as demand forecasts) are fixed to allow customer prices to more accurately reflect final TNUoS rates.

This document contains the discussion of the Workgroup which formed in January 2018 to develop and assess the proposal. Any interested party is able to make a response in line with the guidance set out in Section 5 of this document.

Published on: 4 April 2019

Length of Consultation: 20 Working days

Responses by: 7 May 2019

High Impact:

Suppliers, Generators, embedded generators and National Grid.

Contents

Timetable

The Code Administrator recommends the following timetable:	
Workgroup Consultation issued to the Industry	4 April 2019
Workgroup Meetings	May 2019 – June 2019
Workgroup Report Issued to CUSC Panel	20 June 2019
CUSC Panel meeting to discuss Workgroup Report	28 June 2019
Code Administration Consultation (15 WD)	1 July 2019
Draft FMR presented to CUSC Panel	22 August 2019
CUSC Panel recommendation vote	30 August 2019
Final Modification Report issued to the Authority	2 September 2019
Indicative Decision for the Authority	7 October 2019
Decision Implemented into the CUSC	1 April 2020

Any questions?

Contact:
Code Administrator

Joseph Henry

telephone: 07970673220

Proposer: Daniel Hickman, npower

daniel.hickman@npower.com

telephone: 0121 336 5256

National Grid Representative: Harriet Harmon

Harriet.Harmon@nationalgrid.com

telephone 07970 458456

1. Format of Report

This Workgroup Consultation contains the discussion of the Workgroup which formed in January 2018 to develop and assess the proposal.

Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 4 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The CUSC Panel detailed in the Terms of Reference the scope of work for the CMP287 Workgroup and the specific areas that the Workgroup should consider.

The table below details these specific areas and where the Workgroup have covered them or will cover post Workgroup Consultation.

The full Terms of Reference can be found in Annex 1.

Table 1: CMP287 ToR

Specific Area	Location in the report
a) Workgroup to consider the decision rationale for rejecting CMP244 and how CMP287 will address these	Section 4, Sub Section 1, Pages 10-14
b) Understand the level of fixing in the market place and identify those consumers that would benefit and those that would end up paying more	Section 4, Sub Section 3, Page 16
c) Consider any consequential impacts on other Codes	Section 4, Subsection 5, Page 16
d) Consider the impacts on the outcome of the SCR and what the impacts may be in the way that demand is charged and this needs to be factored in and how fits into the TCR and the wider Charging Futures Forum	Section 4, Sub Section 1, Pages 10-14

e) Consider any if there are any wider issues to consider e.g. any potential Licence changes	Section 4, Subsection 5, Page 16
f) Consideration of whether or what the transitional arrangements should be put in place.	To be further explored by Workgroup

2 CMP287 Original Proposal

Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

Defect

Final TNUoS tariffs are published with a notice period of only 2 months. Suppliers are particularly vulnerable to the short notice period and are reliant on forecasting TNUoS tariffs many months ahead to provide their customers with the fixed price contracts they require.

A typical domestic or business customer, whose meter is settled on non-half hourly data (NHH), and agrees a two-year fixed price contract with their supplier will have TNUoS cost reflected within their contract rates. This will comprise a best view forecast plus an element of risk based on volatility and unpredictability of this charge for the period where final tariffs have not yet been published. If we consider a NHH two-year contract starting in October, TNUoS tariffs are only known for a quarter of the contracted period, the remaining three-quarters being reliant on a forecast.

TNUoS tariffs are set by National Grid System Operator populating a number of inputs into the charging methodology models. Whilst there are some aspects of TNUoS forecasting which are manageable by suppliers and generators, some of these inputs may be known by National Grid but are not published until final tariff setting. In addition, some inputs are fully under the control of National Grid and there is no published methodology on how these are calculated. System and half hourly triad demand, and non-half hourly evening volumes all fall into this category. TNUoS tariffs can be extremely sensitive to these inputs. Market participants are fully reliant on National Grid to provide a view of those inputs through their Quarterly TNUoS forecasting process.

In recent years, we have observed large changes in these volume inputs between National Grid's forecasts over a short period of time. National Grid have confirmed that this has been as a result of 'methodology changes and improvements' to forecasting. However, this results in significant regional changes between National Grid's own quarterly forecasts, draft and final tariffs over very short periods of time. These changes also result in movements between half hourly and non-half hourly tariffs. Given that these National Grid Quarterly Forecasts are the source of this information for marke participants, such volatility can cause unexpected price shifts across the market. This can result in customers' bills which are not reflective of the costs that suppliers incur.

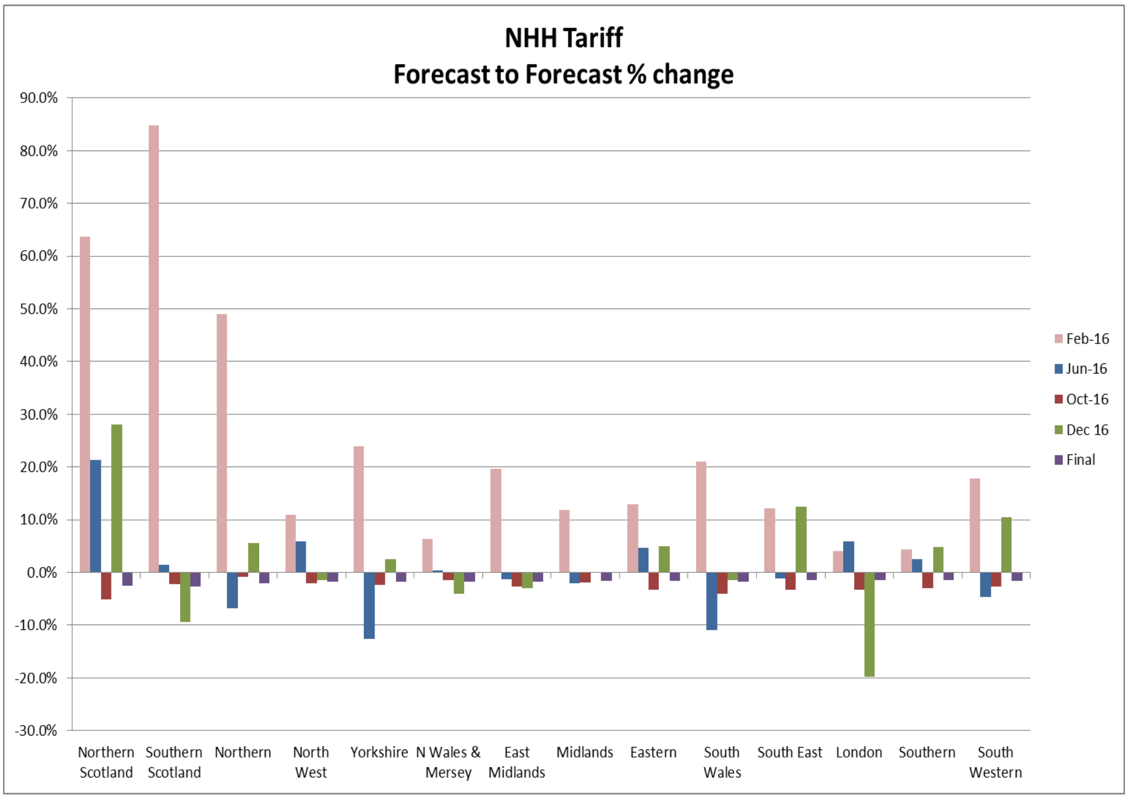
National Grid has endeavoured to assure industry that those inputs are becoming more stable. However National Grid acknowledge they are still highly likely to change these inputs. Given that market participants are trying to predict TNUoS costs as accurately as possible, large and late changes of inputs which significantly affect the calculation of TNUoS prices need to be avoided. Unexpected changes to inputs could have a detrimental impact to those customers who have been contracted using forecast tariffs.

Non Half Hourly Tariff setting for 2017/18 illustrates the issue:

National Grid made changes to the forecasting methodology of their demand forecast inputs in the lead up to publishing tariffs for 2017/18. This process and the risks were not clearly explained to the industry which led to significant volatility in NHH tariffs over four months between October and January.

Graph 1 demonstrates the percentage change to tariffs from one National Grid's forecast to the next for the 2017/18 charging year. It clearly shows volatility. The relationship between the tariff volatility and National Grid's demand forecast volatility is shown on Graph 5-8.

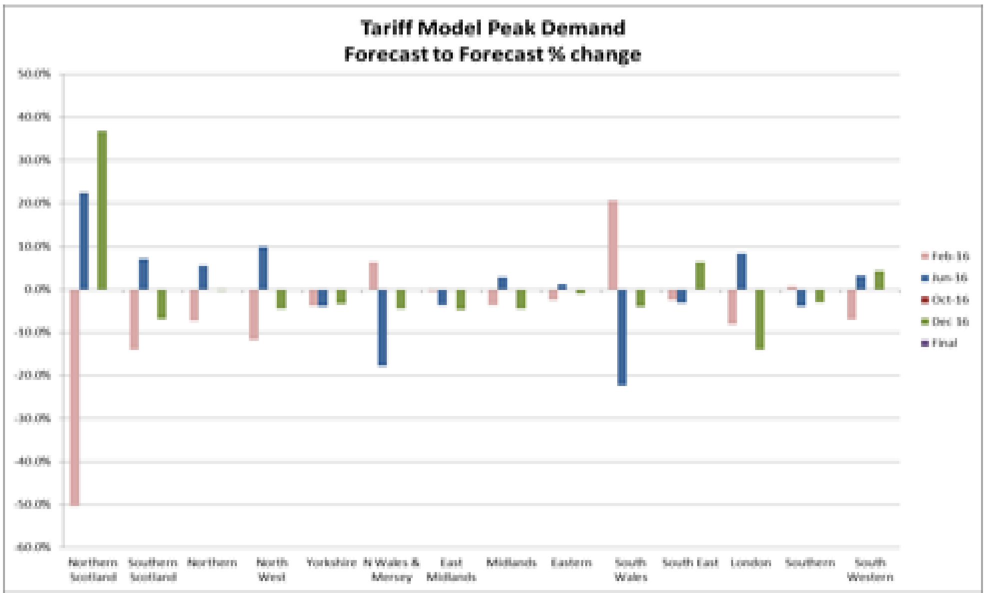
Graph 1

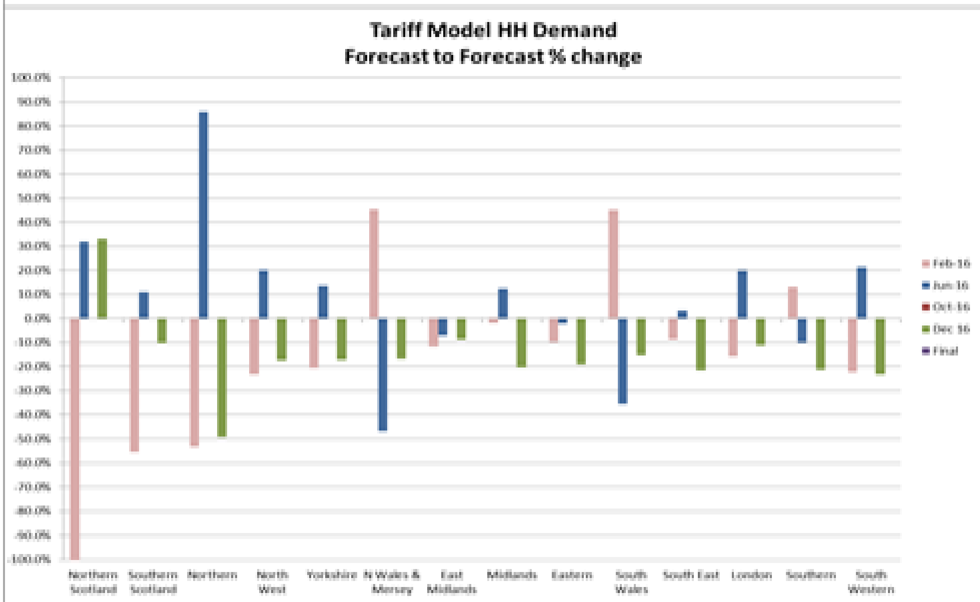


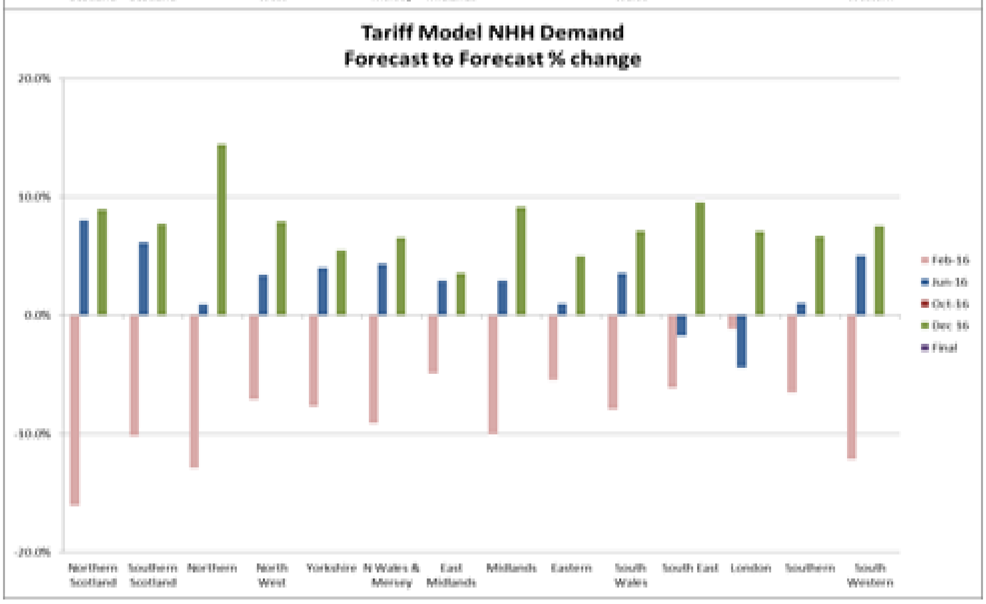
The main driver of this regional forecast volatility is the forecast demand by region due to trying to better forecast embedded generation.

The following charts (Graph 2-4) show the percentage change to demand forecasts from one National Grid's forecast to the next for the 2017/18 charging year.

Graphs 2-4


Tariff Model Peak Demand
Forecast to Forecast % change
Feb-16
Jun-16
Oct-16
Dec-16
Final
Northern Scotland
Southern Scotland
Northern
North West
Yorkshire
N Wales & Mersey
East Midlands
Midlands
Eastern
South Wales
South East
London
Southern
South Western

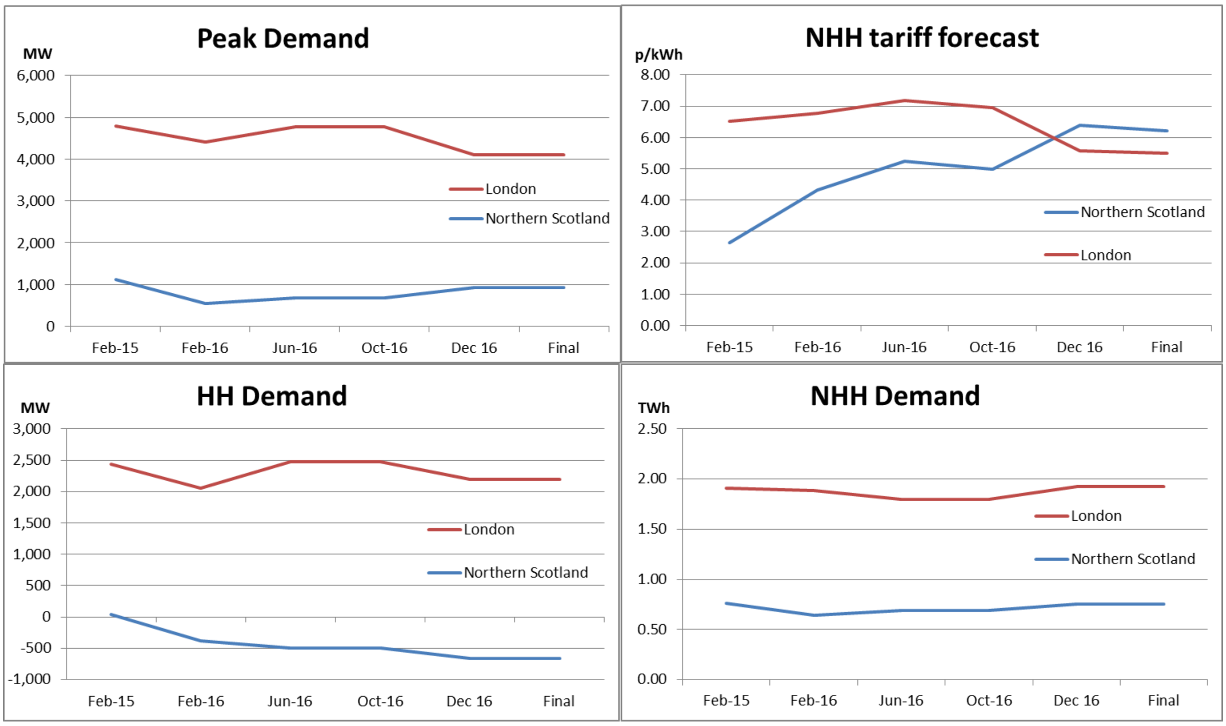

Tariff Model HH Demand
Forecast to Forecast % change
Feb-16
Jun-16
Oct-16
Dec-16
Final
Northern Scotland
Southern Scotland
Northern
North West
Yorkshire
N Wales & Mersey
East Midlands
Midlands
Eastern
South Wales
South East
London
Southern
South Western


Tariff Model NHH Demand
Forecast to Forecast % change
Feb-16
Jun-16
Oct-16
Dec-16
Final
Northern Scotland
Southern Scotland
Northern
North West
Yorkshire
N Wales & Mersey
East Midlands
Midlands
Eastern
South Wales
South East
London
Southern
South Western

What

Forecasts of certain parameters that feed into the TNUoS tariff setting process (including but not limited to the 'tariff model peak demand MW', 'Tariff model HH demand MW' and 'Tariff model NHH demand TWh') are currently volatile and can have significant impact to commercial arrangements offered to customers. These input changes are a significant driver of unpredictable volatility, as shown by the change in TNUoS tariffs forecast by National Grid.

Graph 5-8



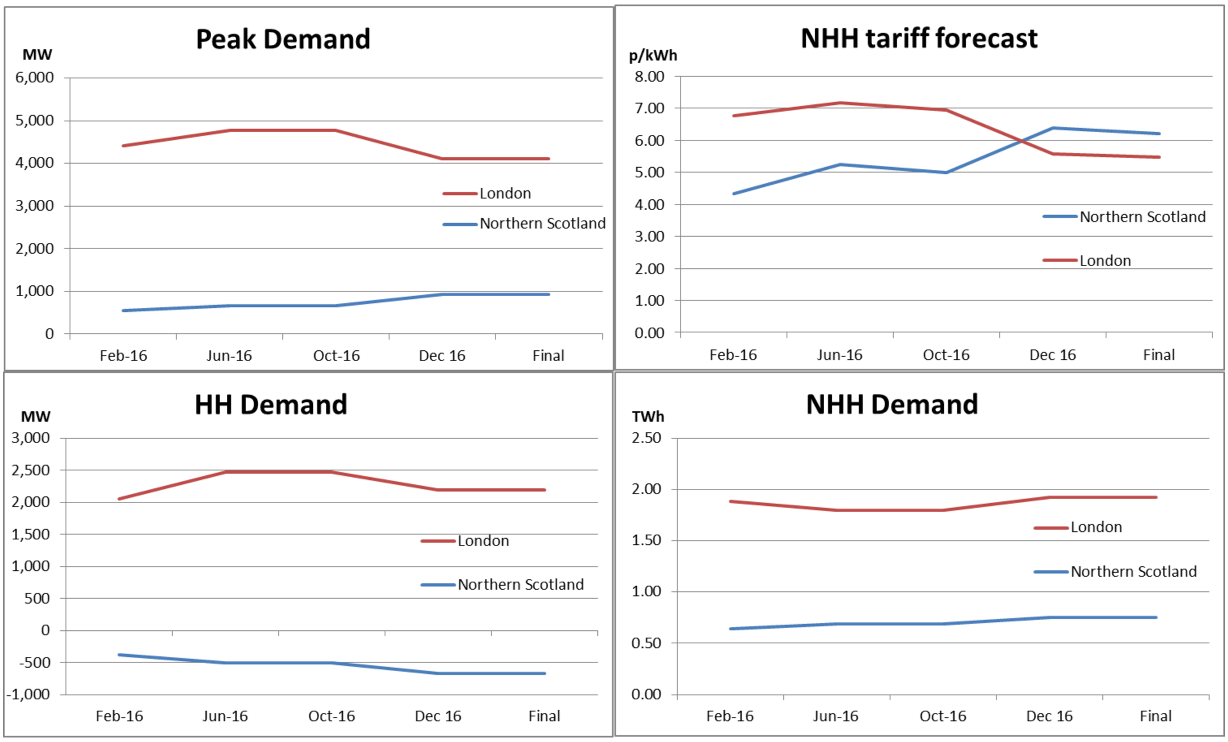
How

The date at which forecasts of certain parameters that feed into the TNUoS tariff setting process (including but not limited to the 'tariff model peak demand MW', 'Tariff model HH demand MW' and 'Tariff model NHH demand TWh') are fixed should be brought forward so that they are fixed earlier in the process to align customer pricing timeline expectations. We would suggest that these inputs should be fixed 15 months ahead of tariffs going live (i.e. 31st Dec yy for tariff year yy+2/yy+3). This aligns with supplier / customer pricing timeline expectations and is consistent with the timescales committed to by DNOs.

Why

Forecasts of certain parameters that feed into the TNUoS tariff setting process (including but not limited to the 'tariff model peak demand MW', 'Tariff model HH demand MW' and 'Tariff model NHH demand TWh') are currently volatile and can have significant impact to commercial arrangements offered to customers. These input changes are a significant driver of unpredictable volatility, as shown by the change in TNUoS tariffs forecast by National Grid.

Graphs 5-8



This makes predicting TNUoS tariffs to include in customer pricing extremely challenging resulting in the need for suppliers to include risk premia.

A typical domestic or business customer, whose meter is settled on non-half hourly data (NHH), and agrees a two-year fixed price contract with their supplier will have reflected within their contract rates TNUoS cost. This will comprise a best view forecast plus an element of risk based on volatility and unpredictability of this charge for the period where final tariffs have not yet been published. If we consider a NHH two-year contract starting in October, TNUoS tariffs are only known for a quarter of the contracted period, the remaining three-quarters being reliant on a forecast.

In recent years, we have observed large changes in these volume inputs between National Grid's forecasts over a short period of time. This results in significant regional changes between National Grid's own quarterly forecasts, draft and final tariffs. These changes also result in movements between half hourly and non-half hourly tariffs. Given that these National Grid Quarterly Forecasts are the source of this information for market participants, such volatility can cause unexpected price shifts across the market. This can result in customers' bills which are not reflective of the costs that suppliers incur. Given that market participants are trying to predict TNUoS costs as accurately as possible for customer pricing, large and late changes of these inputs, which will significantly affect the calculation of TNUoS prices, need to be avoided.

Locking down these inputs earlier in the process removes this element of uncertainty and will allow suppliers to more accurately reflect the final TNUoS tariffs in customers' bills. It will reduce the risk premia.

3 CMP287 Proposer's solution

Section 2 (Original Proposal) and Section 3 (Proposer's solution) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 5 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

The date at which forecasts of certain parameters that feed into the TNUoS tariff setting process (including but not limited to the 'tariff model peak demand MW', 'Tariff model HH demand MW' and 'Tariff model NHH demand TWh') are fixed should be brought forward so that they are fixed earlier in the process to align customer pricing timeline expectations. We would suggest that these inputs should be fixed 15 months ahead of tariffs going live (i.e. 31st Dec yy for tariff year yy+2/yy+3). This aligns with supplier / customer pricing timeline expectations and is consistent with the timescales committed to by DNOs.

Note the Proposer as part of Workgroup deliberations has amended or removed aspects of the proposed solution. These are captured in section 5 of this report

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

It is the view of the Proposer that that they do not believe this modification impacts any areas within the scope of the current SCR.

Consumer Impacts

Customer costs reduced through a reduction in supplier risk premia since there will be more certainty around TNUoS forecasts.

Customers' bills will be more reflective of the costs that suppliers incur.

4 Workgroup Discussions

The Workgroup convened five times between January 2018 and April 2019 to discuss the perceived issue, detail the scope of the proposed defect, devise potential solutions and assess the proposal in terms of the Applicable CUSC Objectives. The Workgroup will in due course conclude these tasks after this consultation (taking account of responses to this consultation).

The Workgroup discussed a number of the key attributes under CMP287 and these discussions are described below.

1. **Context: Why were 'CMP244: Set final TNUoS tariffs at least 15 months ahead of each charging year' and CMP256 'Potential consequential changes to the CUSC as a result of CMP244' rejected, and what has changed since?**

1.1 CMP244, raised in May 2015 by EDF Energy, was rejected by the Authority in July 2016. The decision letter from Ofgem can be found by following the link in the footnote below[1]. CMP244 sought to fix TNUoS 15 months in advance of the relevant charging year, was rejected by The Authority, partly due to insufficient evidence of a quantifiable benefit., although evidence was provided that many of the assumptions around NGESO forecasts were difficult to forecast ahead of time and that it was reasonable to assume that on fixed term contracts, there was a likelihood that terms could be offered that would include a premium to reflect the risk of any forecast.

1.2 Per the Terms of Reference, the CMP 287 Workgroup reviewed the reasons why CMP244 had been rejected by the Authority and what analysis would be needed to support CMP287. The workgroup discussed the issue and agreed that they would need to demonstrate that a detriment to the end consumer exists. Data was collected in a Request for Information (RFI) to Suppliers around their Risk Premia applied in TNUoS to negate perceived issues with volatility. This RFI was published on 31 May 2018 and can be found by following the link in the below footnote[2]

1.3 In CMP287, data collected through Request For Information (RFI) from a number of suppliers, has been able to clearly demonstrate that additional premiums are added to transmission charge tariffs to reflect the uncertainty that demand forecasts have on fixed term contracts. This is explained in further detail in later sections of this report.

1.4 The rationale behind CMP244 was similar to that for CMP287 – a Supplier does not know with certainty what values need to be reflected in customer contracts on their transmission charge liability until such time final tariffs are published (60 days ahead of the 1st April). Contracts agreed before final tariffs are published reflect that uncertainty by adding a risk premium.

1.5 These risk premia – is it argued – could have been reduced/negated under CMP244. For consumers on 'pass-through' contracts (where the consumer pays the Supplier's forecast TNUoS rate and is then reconciled post-triad) it is anecdotally difficult for the Supplier or consumer to understand total TNUoS exposure.

1.6 For consumers on 'fixed' contracts where one p/kWh rate is chargeable throughout the duration of the contract, a risk premium is used to make up any potential shortfall. In order to quantify the benefit of CMP 244, namely a reduction in risk premia, Suppliers would have had to have shared their individual premium to be able to assess the effect across all contracted volumes; because of concerns around competition law, Suppliers were not willing to share this information and the CMP 244 Workgroup was therefore only able to make a qualitative argument as to the benefits of that proposal.

1.7 Like CMP244, CMP287 looks to fix forecast demand TNUoS methodology inputs – 'tariff model peak demand MW', 'Tariff model HH demand MW' and 'Tariff model NHH demand TWh' 15 months ahead of the charging year in which it would apply. This would partially align the transmission charging world to the arrangements seen in UoS charging for distribution (DUoS), where the tariff is published 15 months in advance.

---

[1] https://www.nationalgrideso.com/document/7911/download

[2] The CMP286 and 287 RFI can be accessed here:

https://www.nationalgrideso.com/document/116966/download

The argument has been put forward by the Proposer that fixing elements and inputs of TNUoS tariffs 15 months in advance would reduce the need for suppliers to pass on risk premia to consumers, and therefore reduce the premium itself.

1.8 The CMP287 Workgroup spent time considering the best way to negate the issue of quantifiable benefits throughout the initial Workgroups. The Proposer provided overview of defect to the Workgroup, discussing the forecast in its current iteration showing volatility of NGESO forecast during 16/17. Specifically highlighted in these discussions was the variance between the forecast in November 2015, and the outturn rate for 16/17, showing over £90m, which, the Proposer stated, was likely charged to consumers but were not reflective of the costs that suppliers incurred during this period. October 2016 forecast was also highlighted as showing a particularly noticeable difference between forecasted and charged TNUoS revenue.

1.9 The Proposer presented the solution to the Workgroup, stating the benefits of setting the chargeable demand base input 15 months prior to the relevant charging year. The Proposer confirmed to the Workgroup that the defects which he was looking to address were related to TNUoS Demand Residual (“TDR”) only. It was confirmed by the NGESO representative that the new forecasting timetable was in place, providing a TNUoS forecast in November of each year.

1.10 Workgroup discussions began to centre towards the previous rejections of CMP244 and CMP255, and the aforementioned reasons being the lack of evidence to back up the respective solutions better facilitating CUSC objectives that the baseline provisions.

1.11 The analysis required was discussed at quite some length, however gathering some of the requisite analysis was made difficult for reasons of competition law, an issue which was prevalent throughout CMP244. The Proposer advised the Workgroup that it was his belief that CMP287 was more targeted that the previous modifications and as such would be more robust in nature, to which several Workgroup members agreed.

1.12 A Workgroup member suggested that analysis may show that any fiscal risk of fixing TNUoS inputs may place on NGESO is negligible due to the fact that National Grid is a large organisation. This point was challenged by the NGESO representative, as the modification did pose a risk, in their view, as whilst NGESO will be part of the overall National Grid group of companies, in the same way that a large energy company may have an associated generation business along with a supplier business and would not see losses in one as acceptable if there was profit in the other, NGESO had to be a viable standalone business.

1.13 Questions were also raised by the Workgroup in regard to what information NGESO would provide in their cost benefit analysis. The NGESO representative indicated that they would be happy to take direction and/or suggestions from the Workgroup to enable a sufficient modelling “wish list”. The Workgroup used CMP250 as an example, discussing BSUoS and financing, in order to ascertain the level of financing exposure. NGESO stated that they would establish the level of financial exposure, which would enable the Workgroup to then look at the costs of financing in regard to this modification.

1.14 In terms of analysis needed for CMP287, several scenarios were discussed, each with different permutations, to inform the Workgroup if fixing the TNUoS tariff inputs would result in a benefit to suppliers and consumers. One Workgroup member suggested that a potential way to gain this information would be to look at the potential actions a reasonable supplier would take if the changes were to be implemented. One such scenario suggested was to take a hypothetical example of a fixed price contract, agreed in summer for an October start. Another suggestion was to review what would be the optimal time in a charging for fixing costs. A suggestion was also made by a Workgroup member to look at scenarios involving different sized suppliers, i.e Small, Medium and Large. The Workgroup also suggested that it may be useful if the Authority would give advice or signpost what was missing from CMP244 in terms of what would be required from CMP287 in order to address these issues.

1.15 It became apparent that the analysis of the stakeholder impact and cost reflectivity and the length of fixing costs would also be required. One Workgroup member suggested that this may be the area of analysis which would require the most complexity, and it may be better if the Workgroup approached this with a focus on looking at a view across competition. The potential crossover with the Authority's upcoming Targeted Charging Review/Significant Code Review which covers residual TNUoS cost recovery, was noted by the Workgroup.

1.16 Discussion within the Workgroups also covered at length the disclosure of supplier risk premia applied to consumers to mitigate the potential late fluctuations and volatility in TNUoS forecasting. There was a feeling throughout the Workgroup that due to the commercially sensitive information involved, it would be unlikely that suppliers would wish to divulge this information to industry as a whole. As this was the case, the Workgroup looked at ways in which data could be shared confidentially.

1.17 In Workgroup meeting three, the Proposer explained that in order to asses the financial benefits to consumers a requirement to understand what the reduction in risk premia would be by fixing the volumes (inputs) into the tariff model. The Proposer provided analysis which looked to provide this information without disclosing commercially sensitive information.

1.18 The Proposer initially produced 'proxy data' based on information around TNUoS risk premia that a supplier would have needed to have broken even, were these modifications in place during prior charging years, accounting for variance between forecast and outturn TNUoS. NGESO advised the Workgroup that they would be happy, as a non-supply entity (and thus having no commercial interest in understanding individual supplier's premium), for suppliers to disclose to them their risk premia, and committed to anonymise such data so a more accurate and complete data set could be utilised by the Workgroup in their analysis of CMP287.

1.19 The Workgroup was asked by the Chair to decide if they wished to request actual premia, or to proceed to use the Proxy data provided by the Proposer (which was only produced relevant to CMP 286 but could theoretically be replicated for this proposal). The NGESO representative stated her belief that the RFI would help the progression of the modification, and illustrate to Ofgem that an attempt to gain the data missing for analysis in previous modifications on the subject had been made; if no responses were available then the proxy data could be used instead.

1.20 It was agreed that the RFI should also ask very specific questions (agreed upon by the WG), such as requesting disclosure of risk premia on certain duration contracts, to try and establish an accurate picture. NGESO stated that the RFI and data collection could be carried out by NGESO, who have no commercial interest in or could not potentially take advantage of this commercially sensitive information and are already under obligation not to disclose any data. The Workgroup agreed that this was the best way to proceed. This RFI was consequentially released to Industry on 31 May 2018.

<u>What were the findings of this RFI?</u>

1.21 The Workgroup discussed the findings from the Request for Information (RFI) which was published on the 31 May 2018 requesting disclosure of TNUoS risk premia data[3]. The NGESO representative confirmed that the responses represented a good market share by volume, with over 50% representation for HH volumes, and about a third for NHH (but there are a lot more suppliers within this area). The NGESO representative confirmed that all the Supplier RFI responses have been included within the analysis but one OFTO response had been disregarded. All the data followed a curve so could be viewed as being broadly reflective and neither the highest or lowest values were removed.

1.22 The NGESO representative summarised the findings of the anonymised data and highlighted that the average risk premia on certain contracts would decrease based on the data provided by Suppliers, but on other contracts it would increase were either CMP286, CMP287 or both to be implemented. The summary went on to explain that currently there is a peak in average risk premia on 24 month NHH contracts which disappears if CMP286 and CMP287 were to be implemented.

Please see Annex 2, which details the modelling scenario.

1.23 Some of the comments from the respondents to the RFI suggest that the risk premia for 12 and 24 month contracts would reduce but all you would be doing is deferring the volatility and uncertainty and pushing this further out into the market into the K factor4 which will become apparent and hit in the third year. Suppliers will not be able to mitigate this risk so it will result in an increase in risk premia. 17% of respondents said there would be an increase in risk premia on this basis as there are more risks associated with 3 year contracts where prior years' under/over recovery needs to be factored in. Some respondents to the RFI stated that risk premia would need to be increased to offset anything that would come through the K Factor. Tables are available in Annex 2.

1.24 The workgroup noted that for consumers on short to medium term length fixed contracts there would be a reduction in risk premia but there may be a potential for an increase in risk premia to consumers on longer term contracts, who may end up being penalised by these modifications. The NGESO representative stated this opens up the question of winners and losers in the market and the Workgroup need to consider the extent to which consumers on the 12/24 month deals will benefit in comparison to the detriment of the consumers on the 36 month contracts.

[3] https://www.nationalgrid.com/sites/default/files/documents/CMPs%202867%20Risk%20Premia%20RFI.pdf

[4] Any over or under recovery that stems directly from fixing inputs used to derive tatiffs will be recovered through the K factor 2 years later.

1.25 Some workgroup members opined that customers who contract on 36 months terms may be looking for more budget certainty and are willing to accept additional premia for this benefit. In any market, customers are able to choose optimal terms and if contracts for 12/24 months reduce in cost through lower premia then it could lead to customers moving from 36 months to reduced length contracts and realise these savings. The Workgroup needs to look at this as a whole piece and consider the difference between the two to establish if there is any overall consumer value in implementing these modifications.

1.26 It was opined within the workgroup that the responses may have based on current/next year contracts and there is currently a lot of uncertainty around what the new price control will look like which may have fed into this data. The Workgroup agreed that there are currently a number of unknowns such as the new price control (RIIO T2), what residual charging will look like under the TCR/SCR and legal separation of the SO and TO within National Grid that organisations may have been mindful of when submitting their responses. Nonetheless, the Workgroup noted that there may always be areas of uncertainty and changes happening within the industry which may affect the level of risk premia.

1.27 A query was also raised around if there would be a natural smoothing of the K factor through the years so that the risk premia increase for the 36 months will not appear as high as it currently does. That would also mean that the benefit to the consumers on the 12/24 month contracts may also be lower once this is embedded down.

1.28 It was confirmed by NGESO that any over or under recovery is recovered through the K factor in accordance with the NGESO's Licence. It is hard to say that the detriment on the 36 month contracts is over stated without saying the same for the potential benefits on the 12 and 24 month contracts. Each supplier has its own risk appetite, the impact of the K factor may be compounded on longer term contracts in comparison to shorter contracts. However, the extent of the increase is quite large and the data is from a good cross-section of suppliers, with different risk appetites and business models.

1.29 The Workgroup agreed that all outputs from the RFI should be included within the Workgroup Report regardless of whether they support or quantify the assertions regarding the benefits made by the Proposer. The Workgroup noted that the data does not consider SVA/CVA arrangements in the market and that as each supplier has its own risk appetite and business models certain caveats and disclaimers should be included within the Workgroup Report ahead of the data being published. The Workgroup agreed to discuss this further at a later date.

1.30 It was also noted that demographics and customer numbers in different regions may also have an impact on the data. They recommended that the Workgroup look at the absolute figures rather than the trend, so that the Workgroup report can clearly demonstrate the level of risk premia that is being applied to customers because of the level of uncertainty that is borne of these modifications.

1.31 1.31 There was some disagreement in as much that it could be argued absolute figures are easily challengeable as not being reflective, they should be looking at the high level trends that have come out of the data.
The NGESO representative also noted that a member of the CUSC Panel has requested that both the RFI and Proxy data should be considered together.

1.32 It was also highlighted that the Workgroup now need to decide what volumes they should associate with the risk premia data for HH/NHH splits for fixed and pass through contracts within the market, to establish the total market cost. This would then allow them to establish the notional benefit for the consumer and the increased financial risk to the ESO which would come from the delayed funding and changes in notice periods.

1.33 The Workgroup confirmed this was needed and as such would allow the ESO to identify timelines and costs for implementation and managing the associated risk to understand the impact of the proposed changes. The Workgroup agreed explore what volumes could be used and to check if there is any high level independent data or market reviews from Ofgem, Cornwall Insights or the Competition Markets Authority (CMA) that could provide this information. The Workgroup agreed that if this data is not available then they will need to work out a weighted average based on available portfolios.

1.34The NGESO representative noted that the Workgroup still need to clarify if risk premia is applied to non-fixed products such as Deemed/Out of Contract/28-day Notice Plans and what happens to customers who are on these default non contractual price plans. They also need to consider if there is any desire to weight the data by market share volume. The NGESO representative confirmed that weightings for HH would make a relatively small difference, but is yet to try this for NHH.

2. Which Party is better placed to manage the risk and provide consumer benefits?

2.1 The view of the Proposer, broadly supported by most of the Workgroup is that National Grid as a holding company has a lower cost of capital than Suppliers and could finance the risk more cheaply. The NGESO representative disagreed with this view and questioned whether – if you disregarded National Grid's holding company – it is the view of the Proposer and Workgroup that it is the responsibility of the ESO (even if it was a government dept. or non-profit) to bear TNUoS risk on behalf of industry.

3. What is the current Customer base and contract types? What is the level of fixing in the market place?

3.1 It was suggested that there would be some consumers who would not benefit from this modification, namely consumers on contracts (specifically pass through) with a duration of more than 2 years, on the basis that the K adjustments of any under- or over-recovery would make their way into the second or third year's charge.

3.2 It was argued in a consultation response to CMP244 that some sophisticated consumers may chose to include in their cost base the risk associated to their energy contracts. The goods and services they then sell feature the cost of that risk, and therefore the risk is borne by all consumers. For example, a glass manufacturer increasing his prices to reflect his view of the risk in his energy contract.

3.3 The Workgroup discussed this point and the Workgroup member from Cornwall Energy was asked to consider whether he was able to provide data on the level of fixed vs. pass through contracts in the market and the timings of such contracts (i.e. when they're agreed). Cornwall Energy agreed to look into the feasibility of this action.

4. What is the optimal time for fixing costs?

4.1 The Workgroup discussed whether there were alternatives in terms of timescales – rather than 15 months, perhaps fix at 6,9 or 12 – the NGESO representative asked why 15 months had been stipulated and the Proposer confirmed that it was to align with DCUSA provisions. The Workgroup agreed to look at possible alternatives in timings if they were raised post-consultation.

5. What are the Impacts on Other Codes and Licenses?

5.1 The Workgroup can not foresee any impacts on other codes, as the TNUoS charging methodology is managed solely within the Connection Use of System Code. The same finding is true for License impacts.

6. How will this modification be implemented?

6.1 The NGESO representative stated that the implementation date would need to be clearly defined in the legal text and proposed April of the next applicable charging year as a suggestion to allow National Grid time to put appropriate processes in place to facilitate the modifications should they be approved.

5.2 The Workgroup discussed which part of the legal text would need to be updated in order for the modification to be implemented. The Workgroup agreed that the principles in 14.29 should be updated with a sign post to a new section which would cover the technical detail.

7. Targeted Charging Review

7.1 Since this Workgroup began, The Authority has issued its minded-to decision on the future of residual charging under the Targeted Charging Review[5] As confirmed by the Proposer, CMP287 seeks only to fix the chargeable demand base input into the TNUoS methodology - this input only affects the calculation of the TNUoS Demand Residual Charge.

7.2 Under The Authority's minded-to decision, the TNUoS Demand Residual charge will be a fixed charge, with Suppliers being charged either: a value linked to a SVA consumer's DUoS category (Line Loss Factor Class - 18 categories of end user as provided for in the Distribution Connection and Use of System Agreement Common Distribution Charging Methodology); or a value linked to a consumer's specific capacity on the Distribution network. In either case, the current chargeable demand base as an input into the TNUoS Charging Methodology will be different in future years than it is today.

7.3 The Workgroup is cognisant of this development but, until such time as The Authority makes a determination as to what will constitute the chargeable demand base in future, can only continue to assess this CUSC Modification Proposal against the baseline CUSC Charging Methodologies. The Workgroup accepts that the results of the RFI (per Appendix 2) are predicated on today's methodology - if the charging base changes such that it becomes more static (i.e. non-volumetric), a further RFI may be required to reassess the benefits of this CMP287.

---

[5] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-minded-decision-and-draft-impact-assessment

5 Workgroup Consultation questions

The CMP287 Workgroup is seeking the views of CUSC Parties and other interested parties in relation to the issues noted in this document and specifically in response to the questions highlighted in the report and outlined below:

Standard Workgroup Consultation questions:

Q1: Do you believe that CMP287 Original proposal better facilitates the Applicable CUSC Objectives?

Q2: Do you support the proposed implementation approach?

Q3: Do you have any other comments?

Q4: Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?

Specific CMP287 Workgroup Consultations Questions:

Q5: Who should bear the risk of TNUoS volatility – the market, or the ESO? Why?

Q6: Is 15 months the optimum time period? If you disagree, please suggest a timeframe and reasoning.

Q7. Please provide comment on the benefits analysis contained in Annex 2.

Please send your response using the response proforma which can be found on the National Grid website via the following link:

https://www.nationalgrid.com/uk/electricity/codes/connection-and-use-system-code/modifications/improving-tnuos-predictability

In accordance with Section 8 of the CUSC, CUSC Parties, BSC Parties, the Citizens Advice and the Citizens Advice Scotland may also raise a Workgroup Consultation Alternative Request. If you wish to raise such a request, please use the relevant form available at the weblink below:

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

Views are invited upon the proposals outlined in this report, which should be received by **5pm** on **7 May 2018**. Your formal responses may be emailed to: cusc.team@nationalgrid.com

If you wish to submit a confidential response, please note that information provided in response to this consultation will be published on National Grid's website unless the response is clearly marked "Private & Confidential", we will contact you to establish the extent of the confidentiality. A response marked "Private & Confidential" will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the CUSC Modifications Panel or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Please note an automatic confidentiality disclaimer generated by your IT System will not in itself, mean that your response is treated as if it had been marked "Private and Confidential"

6 Relevant Objectives

Impact of the modification on the Applicable CUSC Objectives (Charging):	
Relevant Objective	Identified impact
(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;	Positive
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	Positive
(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;	None
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1*; and	None
(e) Promoting efficiency in the implementation and administration of the CUSC arrangements.	None
*Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).	

Final TNUoS tariffs are published with a notice period of only 2 months. Suppliers are particularly vulnerable to the short notice period and are reliant on forecasting TNUoS tariffs many months ahead to provide their customers with the fixed price contracts they require.

This modification will give more certainty to inputs into the TNUoS Charging Methodology that market participants cannot forecast, thereby making the costs that customers pay more reflective of the final charge and consequently reduce the risk premia charged by suppliers. This will reduce the price distortions in the competitive market thereby facilitating effective competition in retail energy supply.

7 Implementation

Proposer's initial view:

by the 31st December following approval, to provide notice of the chargeable demand inputs to be used in tariff setting for the following two charging years.

I.e. providing 3 months of notice ahead of the next charging year and the full 15 months of notice for following year.

For example: approval received prior to 31st December 2019, by the 31st December 2019 to provide details of the chargeable demand forecasts to be used in tariff setting for 20/21 and 21/22 charging years.

.

8 Legal Text

The draft legal text changes are still being developed.

9 Annex 1: Terms of Reference

CMP287 seeks to improve the predictability of TNUoS demand charges by bringing forward the date at which certain parameters used in TNUoS tariff setting (such as demand forecasts) are fixed to allow customer prices to more accurately reflect final TNUoS rates.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal CMP287 Improving TNUoS Predictability through Increased Notice of Inputs Used in the TNUoS Tariff Setting Process tabled by npower at the Modifications Panel meeting on 20 October 2017.

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

Charging Applicable Objectives

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

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

(e) Promoting efficiency in the implementation and administration of the system charging methodology.

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) Workgroup to consider the decision rationale for rejecting CMP244 and how CMP287 will address these
b) Understand the level of fixing in the market place and identify those consumers that would benefit and those that would end up paying more
c) Consider any consequential impacts on other Codes
d) Consider the impacts on the outcome of the SCR and what the impacts may be in the way that demand is charged and this needs to be factored in and how fits into the TCR and the wider Charging Futures Forum
e) Consider any if there are any wider issues to consider e.g. any potential Licence changes
f) Consideration of whether or what the transitional arrangements should be put in place.

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 working days** as determined by the Modifications Panel.

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

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

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on TBC for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting in June 2019.

Membership

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

Role	Name	Representing
Chair	Shazia Akhtar	National Grid ESO Code Administrator
National Grid Representative	Harriet Harmon	National Grid ESO
Industry	Daniel Hickman	RWE Npower

Representatives	James Anderson Robert Longden Garth Graham Binoy Dharsi Peter Bolitho Karl Maryon Gregory Edwards	Scottish Power Cornwall Insight SSE EDF Waters Wye Haven Power Centrica
Authority Representatives	Sean Hennity	OFGEM
Technical secretary	Joseph Henry	National Grid ESO Code Administrator
Observers	Richard Woodward	National Grid TO

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 CMP287 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.

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

The Code Administrator recommends the following timetable:	
Workgroup Consultation issued to the Industry	4 April 2019
Workgroup Meetings	May 2019 – June 2019
Workgroup Report Issued to CUSC Panel	20 June 2019
CUSC Panel meeting to discuss Workgroup Report	28 June 2019
Code Administration Consultation (15 WD)	1 July 2019
Draft FMR presented to CUSC Panel	22 August 2019
CUSC Panel recommendation vote	30 August 2019
Final Modification Report issued to the Authority	2 September 2019

Indicative Decision for the Authority	7 October 2019
Decision Implemented into the CUSC	1 April 2020

10 Annex 2: Scenario Modelling

This document, which has been prepared by the ESO outlines the process followed for the analysis of the data received in response to the Request for Information issued on 31 May 2018 by National Grid (hereafter, "the RFI").

Background:

On 31 May 2018, NGESO issued the RFI to request that Suppliers share information relating to any risk premia they include within consumer pricing to mitigate potential TNUoS volatility. The RFI was left open for four (4) weeks. Respondents were asked to send their responses directly to the NGESO representative for CMPs 286 & 287. The RFI asked whether Suppliers currently included – in their 'fixed price' contract offerings - risk premia specifically for TNUoS, the value of such premia (split by Non-Half Hourly (NHH)/Half Hourly (HH) and contract duration) and the value of such premia if either or both of the relevant CMPs were implemented. Suppliers were also invited to add any individual commentary that they believed would aid in the assessment of the modifications.

Responses:

- The ESO has deleted all original responses and no longer has information as to which Supplier gave which values;
- To assist in maintaining confidentiality of responses, the number of respondents has not been shared with any person external to the ESO (on the basis that a respondent could potentially reverse-engineer approximations of other Suppliers' premia if they knew how many parties' data was involved);
- One response was excluded from all calculations because the respondent is not a Supplier and inclusion of their data would skew the averages unnecessarily;
- Some responses were not in the requested format and needed to be converted (e.g. ranges were provided) – no manipulation of the data has otherwise taken place

Assessing the effect of the mods:

- The p/kWh values:
    - Each Supplier's data was pulled into one overall 'master' sheet to serve as a working document;
    - Unweighted averages of the premia currently used in 12, 24 and 36 month contracts, split by NHH and HH, were derived, as were those potentially to be used following implementation of either or both mods being approved;
    - Both percentage and absolute variances were then noted and are shown in Table 1;
- The Workgroup agreed that a total £m value would be beneficial in illustrating the effect of the mods. To that end:
    - For Domestic Consumers, ESO used both Ofgem's Typical Domestic Consumption Values[6] ("TDCV") and BEIS/ONS' publication on the total aggregate domestic

[6] https://www.ofgem.gov.uk/gas/retail-market/monitoring-data-and-statistics/typical-domestic-consumption-values

consumption in 2017[7] to find that a typical (medium user) Domestic Consumer will use 3100kWh/year, and all Domestic Consumers in aggregate used 105391GWh in 2017;

- Multiplying the TDCV by the average NHH 12, 24 and 36 month risk premia as it stands today, and as it would under either or both modifications, provides an illustration as to the notional annual effect of the modifications as illustrated in Table 2;
- A £m total was derived by considering the total Domestic volume which is 'fixed' (using recent Ofgem publications it was determined that 44% of Domestic volume is in fixed price contracts) and so multiplying the average NHH 12, 24 and 36 month risk premia as it stands today and as it would under either or both modifications provided an illustration of the notional aggregate annual effect of the modifications as shown in Table 3;
- The Workgroup agreed that information relating to the split between the Domestic MWh volumes attributable to 12-month, 24-month and 36-month contracts was not available and as such asked the ESO to provide further scenario modelling using hypothetical percentage splits between the three contract durations. The resultant output is shown in Tables 4a – 4g
- Information relating to the contractual arrangements in the Non-Domestic market could not be obtained by this Workgroup. Initially it had been considered that it might be possible to make some broad assumptions - for instance, one Supplier provided the ESO with a typical MWh consumption value for a HH Non-Domestic consumer, which, alongside the Micro Business threshold of 100MWh (per the Standard Conditions of the Electricity Supply Licence) could have been used to model the potential MPAN-level effect of the modifications for typical HH and larger Micro Business consumers; the Proposer stated, however, and the Workgroup broadly agreed that it was better to leave this sort of modelling to the Authority if they felt it would be beneficial to their decision-making process. As a result, there is no information provided regarding the materiality of the effect on individual segments or consumer types within the Non-Domestic market. Table 5 shows the effect of both modifications on the whole Non-Domestic market, using DUKES[8] data for the remaining total consumption.

Assumptions/parameters agreed by the Workgroup:

- All other things being equal;
- All Domestic Consumers are NHH;
- Unweighted UK consumption data used – GB data unavailable;
- The values in the BEIS/ONS data relating to Domestic consumption in 2017 would remain static, as would the TDCV and the DUKES base UK consumption;

NB: in all Tables, negative values indicate an <u>increase</u> in premia

Table 1 – typical premia and notional variances:

Premium description	12 month p/kWh	24 month p/kWh	36 month p/kWh
NHH current average	0.028	0.073	0.070
HH current average	0.012	0.045	0.030
NHH under 286	0.021	0.040	0.073
HH under 286	0.009	0.016	0.036
NHH under 287	0.019	0.037	0.071
HH under 287	0.008	0.014	0.035

[7] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/729317/Energy_Consumption_in_the_UK__ECUK__2018.pdf

[8] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/736152/Ch5.pdf

NHH under both mods	0.010	0.030	0.075
HH under both mods	0.005	0.009	0.041
Variance	**12 month contract**	**24 month contract**	**36 month contract**
% change NHH - 286	25%	45%	-6%
% change HH - 286	20%	66%	-21%
% change NHH - 287	32%	49%	-2%
% change HH - 287	29%	69%	-15%
% change NHH - both	63%	59%	-8%
% change HH - both	61%	81%	-36%

Table 2 – consumer-level effect of modifications, domestic:

Risk Premia Description	Value	VAR
Total current Domestic, 12 month	£0.86	-
Total current Domestic, 24 month	£4.52	-
Total current Domestic, 36 month	£6.47	-
Domestic under 286, 12 month	£0.64	£0.22
Domestic under 286, 24 month	£2.49	£2.03
Domestic under 286, 36 month	£6.83	-£0.36
Domestic under 287, 12 month	£0.58	£0.27
Domestic under 287, 24 month	£2.32	£2.20
Domestic under 287, 36 month	£6.63	-£0.16
Domestic under both, 12 month	£0.32	£0.54
Domestic under both, 24 month	£1.87	£2.65
Domestic under both, 36 month	£6.97	-£0.50

A Domestic Consumer on a 12-month plan currently pays £0.86 per year in TNUoS risk premium. Under CMP 286, that consumer would save £0.22 per year in premium, £0.27 under CMP 287 and £0.54 per year if both modifications were implemented. Consumers on 36-month contracts would see their risk premia costs increase.

Table 3 – aggregate effect of modifications, domestic, no portfolio weighting:

Type	Value	VAR (£)
Total fixed kWh	46,372,040,000	-
Total current domestic premia £	26,292,946	-
Total 286 domestic premia £	20,728,301	5,564,644
Total 287 domestic premia £	19,708,117	6,584,829
Total both £	17,806,863	8,486,083

Broadly, Domestic consumers spend in aggregate c.£26m per year on Supplier TNUoS risk premia. This value could drop by c.£8m per year if both modifications were implemented but the individual effect on a consumer is determined by their contract duration.

The total current domestic premia, and potential premia under 286/7/both in £ were derived by multiplying the average NHH risk premia (smeared across all contract durations, unweighted) for each scenario by the domestic volume associated to 'fixed' contracts.

Table 4a – aggregate effect of modifications, domestic – if all fixed price Domestic contracts were of a 12-month duration

If 100% of Fixed Price Domestic Volume ("FPDV") was on a 12 month			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total fixed kWh	46,372,040,000	-	
Total "current" domestic premia £	12,790,954	-	
Total 286 domestic premia £	9,544,911	3,246,042	25%
Total 287 domestic premia £	8,694,757	4,096,196	32%
Total both £	4,753,134	8,037,820	63%

Table 4b – aggregate effect of modifications, domestic – if all fixed price Domestic contracts were of a 24-month duration

If 100% of FPDV was on a 24 month			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total fixed kWh	46,372,040,000	-	
Total current domestic premia £	33,774,302		
Total 286 domestic premia £	18,587,459	15,186,843	45%
Total 287 domestic premia £	17,350,871	16,423,430	49%
Total both £	13,950,255	19,824,047	59%

Table 4c – aggregate effect of modifications, domestic – if all fixed price Domestic contracts were of a 36-month duration

If 100% of FPDV was on a 36 month			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total fixed kWh	46,372,040,000	-	
Total current domestic premia £	32,267,211		
Total 286 domestic premia £	34,044,806	-1,777,594	-6%
Total 287 domestic premia £	33,040,078	-772,867	-2%
Total both £	34,740,386	-2,473,175	-8%

Table 4d – aggregate effect of modifications, domestic – if Domestic contracts were split evenly 33% on 12, 24, 36 month

If 33% of FPDV was on a 12/24/36			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total fixed kWh	46,372,040,000	-	
Total current domestic premia £	26,014,714		

Total 286 domestic premia £	20,518,468	5,496,246	21%
Total 287 domestic premia £	19,498,283	6,516,430	25%
Total both £	17,636,446	8,378,268	32%

Table 4e – aggregate effect of modifications, domestic – if Domestic contracts were split 50% on 12-month, 25% on 24 & 25% on 36

If 50% of FPDV was on a 12 month (25% on 24, 25% on 36)			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total fixed kWh	46,372,040,000	-	
Total current domestic premia £	22,905,855		
Total 286 domestic premia £	17,930,522	4,975,333	22%
Total 287 domestic premia £	16,945,116	5,960,739	26%
Total both £	14,549,227	8,356,628	36%

Table 4f – aggregate effect of modifications, domestic – if Domestic contracts were split 50% on 24-month, 25% on 12, & 25% on 36

If 50% of FPDV was on a 24 month (25% on 12, 25% on 36)			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total fixed kWh	46,372,040,000	-	
Total current domestic premia £	28,151,692		
Total 286 domestic premia £	20,191,159	7,960,533	28%
Total 287 domestic premia £	19,109,144	9,042,547	32%
Total both £	16,848,507	11,303,184	40%

Table 4g – aggregate effect of modifications, domestic – if Domestic contracts were split 50% on 36-month, 25% on 12, & 25% on 24

If 50% of FPDV was on a 36 month (25% on 12, 25% on 24)			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total fixed kWh	46,372,040,000	-	
Total current domestic premia £	27,774,919		
Total 286 domestic premia £	24,055,495	3,719,424	13%
Total 287 domestic premia £	23,031,446	4,743,473	17%
Total both £	22,046,040	5,728,879	21%

Table 5 – aggregate effect of modifications, Non-Domestic, assumes 50% NHH, 50% HH, smeared premia across all contract durations

Aggregate effect on Non-Domestic Market, 50/50 NHH/HH split			
Type	**Value**	**Benefit (£)**	**Benefit (%)**
Total Market Consumption, 2017, kWh	353,000,000,000	-	

Total Domestic Consumption 2017, kWh	105,391,000,000	-	
Total Non-Domestic Consumption 2017, kWh	247,609,000,000		
Total Current Premium (£)	105,844,023		
Total if 286 implemented (£)	80,513,098	25,330,925	24%
Total if 287 implemented (£)	75,910,361	29,933,662	28%
Total if both implemented (£)	69,767,815	36,076,208	34%

11 Annex 3 – Attendance Log

Name	Company/role	Role	18/01/2018	12/03/2018	18/05/2018	31/07/2018	17/08/2018	17/09/2018
Caroline Wright	National Grid (Chair)	Chair	A	A	X	X	X	X
Teresa Thompson	National Grid (Tech Sec)	Tec Sec	A	A	X	X	X	X
Joseph Henry	National Grid (Chair)	Tec Sec	X	X	A	A	A	A
Shazia Akhtar	National Grid (Tech Sec)	Chair	X	X	A	A	A	A
Daniel Hickman	Npower (Proposer)	Proposer	A	A	A	A	A	A
James Anderson	Scottish Power	WG Member	A	A	A	A	A	A
Robert Longden	Cornwall Energy	WG Member	A/D	A/D	X	A/D	A	A
Garth Graham	SSE	WG Member	X	X	X	X	X	X
Andy Colley	SSE	WG Alternate	A	A	A/D	A/D	A	A
Binoy	EDF	WG	A/D	A	x	A/D	A	A

Dharsi		Member						
Simon Vicary	EDF	WG Alternate	x	x	A/D	x	x	x
Harriet Harmon	National Grid	WG Member	A	A/D	A	A/D	A	A
Peter Bolitho	Waters Wye	WG Member	A	A	A	A/D	A	A
Karl Mayron	Haven Power	WG Member	A	A	A/D	A/D	A/D	A/D
Gregory Edwards	Centrica	WG Member	A	A	A	A/D	A	A
Sean Hennity	Ofgem	Observer	A/D	A	A/D	A/D	A/D	A/D
Richard Woodward	National Grid (TO)	Observer/info only	X	A	X	X	X	X

