Stage 03: Workgroup Report

At what stage is this document in the process?

CMP282: 'The effect Negative Demand has on Zonal Locational Demand Tariffs'

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

Purpose of Modification: CMP282 seeks to amend how the DCLF model calculates Zonal Locational Demand tariffs so that the final locational zonal demand tariffs accurately reflect the underlying locational signals.

This document contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal, the responses to the Workgroup Consultation which closed on 14 August 2017, the voting of the Workgroup held on 6 September August 2017 and the Workgroup's final conclusions.

High Impact:

Suppliers and Embedded Generators

As this modification aims to amend the Demand tariffs this modification will definitely affect Suppliers and Embedded Generators and potentially Transmission Connected Generators (depending on the final proposed solution).

Low Impact:

Transmission Companies.

The Workgroup concludes:

All Workgroup Members concluded that the Original proposal facilitates the Applicable CUSC Objectives better than the baseline. No potential Workgroup Alternative Consultation Modifications (WACMs) were proposed.

Contents

Timetable

The Code Administrator recommends the following timetable:	
Workgroup Report presented to Panel	29 September 2017
Code Administration Consultation Report issued to the Industry	2 October 2017
Draft Final Modification Report presented to Panel	19 October 2017
Modification Panel decision	27 October 2017
Final Modification Report issued the Authority	3 November 2017
Decision implemented in CUSC	1 December 2017

Any questions?

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1 About this document

This document is the Workgroup Report that contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal, the responses to the Workgroup Consultation which closed on 14 August 2017, the voting of the Workgroup held on 16 August 2017.

CMP282 was proposed by National Grid and was submitted to the CUSC Modifications Panel for its consideration on 30 June 2017. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the CUSC Applicable Objectives. The Authority determined that the proposal should ***not*** be considered on an Urgent timescale but follow accelerated timescales. The letter from the Authority setting out the reasons for urgency is set out in **Annex 2**.

CMP282 aims to amend how the DCLF model calculates Zonal Locational Demand tariffs so that the final locational zonal demand tariffs accurately reflect the underlying locational signals. The Workgroup consulted on this Modification and a total of 6 responses were received. These responses can be views in Section 8 of this Report.

Workgroup Conclusions

At the final Workgroup meeting, Workgroup members voted on the Original proposal. All members voted that the Original Proposal better facilitated the applicable CUSC objectives as it reflected the licence changes.

2 Format of this report and Terms of Reference

This report contains the discussion of the Workgroup which formed in July 2017 to develop and assess the proposal.

Section 4 (Original Proposal) and Section 5 (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 7 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 CMP282 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: CMP282 ToR

Specific Area	Location in the report
a) Consider the practical implications of solution e.g. that data is available to National Grid to support the proposed solution and any system changes.	Section 7. Confirmed that no changes required to the billing system just changing the code used to calculate tariffs.

b) Consider the impact on the locational signals.	Section 7. Solution will not change the locational signals but just changing the way signals are translated into zonal tariffs.
c) Consider the interaction with other open Modifications.	Section 7. Workgroup consider the work taking place under CMP276 and the SQSS GSR016 Workgroup.

3 Executive summary

What is the defect?

For every location (node) on the Transmission System we model the impact on System flows of adding an extra 1MW of Generation at that location. If the signal is positive then adding 1MW at that location increases flows on the system. If negative then adding 1MW decreases flows on the System.

Nodes are grouped into Zones to try and add stability to tariffs. The locational signal for a zone is based on all the nodes within that zone. The nodal signal is weighted so that nodes with greater amounts of Demand or Generation than other nodes, impact on the Final Zonal tariff more than other nodes.

The mathematical calculation works correctly when all Demand nodes import. However, when a Demand node starts to Export, due to the mathematics this acts to inverse the nodal signal when calculating the Zonal Demand tariff. This modification aims to correct the defect so that locational signals are accurately reflected in the end Demand tariff

What is the impact of the Defect?

The defect has manifested itself in Demand Zone 1. Demand Zone 1 has seen an increase in its forecasted Demand Tariffs for 2018/19, whereas the underlying locational signals indicate that the Demand Tariff should be decreasing. Without this modification end consumers may see their Transmission Liability double (in Northern Scotland).

What is the proposal?

The defect manifests itself when nodes begin to Export. Therefore all proposals seek to change the mathematical calculation so that Exporting Nodes do not distort the final Zonal Demand Tariff.

- The Original Proposal achieves this by ignoring Exporting Nodes when calculating the Zonal Demand Tariff.
- Other proposals were evaluated, which also solved the defect. They achieved this by turning Exporting Nodes into Importing Nodes. Although the defect was solved, these proposals were dismissed by the Workgroup as they solved the defect by manipulating data. The Workgroup felt as a whole that Exporting Nodes should affect the Generation Tariff and if this cannot be achieved then they should be ignored.
- Following on from above, a solution where Exporting Nodes were not ignored and were taken into account in the Zonal Generation Tariff was also evaluated by the Workgroup. This had the potential to be a better solution than the original as all nodes and their locational signal, affected either a Zonal Demand Tariff or a Zonal Generation Tariff, rather than being ignored. However a number of Workgroup members noted that Generation at a node is scaled to match demand, with Generation Types scaled differently. Simply moving an Exporting Node and treating as Generation would solve one distortion whilst creating a new one, noting that there are Grid Code Modifications currently in progress regarding how to take into account Embedded Generation when planning Transmission Investment. If or when these modifications are implemented this

may potentially allow Exporting Nodes to be included within the Zonal Generation Tariff through a modification change.

- As the defect needs to be addressed as quickly as possible, the original proposal is the best way to achieve this.

<u>How will the Proposal Change Demand Tariffs?</u>

Table 7 within the document illustrates how the proposal will alter forecasted Demand Tariffs for 2018/19. Demand Zone 1 will see a decrease in its forecasted Tariffs as this zone contains by far the most Exporting nodes. Due to the tariff decrease less revenue is recovered from this zone, which therefore results in the Demand Residual increasing to make up for this reduction so all Demand Zones are affected.

<u>As a Supplier what do I need to do?</u>

The answer to this question is not a lot. Current TNUoS forecasts for 2018/19 are based on the baseline (i.e. include the defect). The proposal will not change the tariff structure or involve any changes to how demand is forecasted. As a Supplier please therefore take into account that forecasted Demand Tariffs for 2018/19 may alter due to this modification in the magnitude shown in Table 7. Timescales mean that any decision on this modification will be made before Final Demand Tariffs for 2018/19 become fixed.

<u>What about previous years Tariffs?</u>

The Workgroup noted that the defect has always been there within the calculation. However for 2018/19 the number of Exporting GSPs has substantially increased, due to updated demand forecasts and new connections. The defect has therefore become material. The Workgroup looked at how previous years tariffs would have changed if the proposed solution had been implemented for that charging year and found that the change to Demand Tariffs would have been minimal, whereas for 2018/19 the changes for Demand Zone 1 are material.

<u>Will this change be the enduring solution?</u>

The Proposer and the Workgroup noted should the original solution for CMP282 be implemented that this would be the enduring solution for all future Charging Years until the point another modification was raised and implemented.

4 Original Proposal

Section 4 (Original Proposal) are sourced directly from the Proposer and any statements or assertions have not been altered or substantiated/supported or refuted by the Workgroup. Section 7 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

Defect

Final Zonal Locational Demand Tariffs most notably in North Scotland are distorted by nodes which are forecasted to Export at Peak when the Demand Zone is forecasted to Import or Import when the Demand Zone is forecasted to Export. The defect itself is contained within the calculation in the tariff part of the DCLF model which turns underlying locational signals into zonal weighted demand, and **not** the locational signals themselves within the Transport part of the DCLF model.

Why change

If the defect is not resolved Demand tariffs will not accurately reflect the costs imposed on the System by taking demand at that particular location. Where Demand tariffs do not reflect underlying costs, end users will pay more or less than what is required (if someone pays more, then someone will pay less) This creates inefficient investment signals and may go so far as to incentivises adverse behaviour to the investment signal.

The Locational signal, plus total demand at Peak determines how much revenue is required to be recovered from a particular demand zone. If the locational demand tariff increases, an increased amount of revenue is required to be recovered from that zone. If underlying demand has not actually changed then this results in Non-Half Hourly charges rising substantially more than Half Hourly charges as NHH charges act as a Residual recovery mechanism for that zone. This explains why the forecasted NHH tariff for 18/19 rises more as a percentage change greater than HH tariffs in Zone 1.

What

When calculating the incremental cost for a particular location on the Transmission Network, National Grid uses the DCLF ICRP transport model. The DCLF model calculates the impact of adding 1MW of Generation at that particular location has on base flows under both the Peak and Year Round Scenarios.

When calculating the incremental impact of adding 1MW of Generation the model also calculates the impact of adding 1MW of Demand at the same location. The impact of adding 1MW of Demand is the inverse effect of adding 1MW of Generation. The locational tariff for Demand is therefore achieved by multiplying the nodal locational signal for Generation by -1 to calculate the locational tariffs for Demand.

Tariffs are calculated on a Zonal basis to provide stability. To calculate the zonal locational tariff, the locational signal for a particular node is weighted according to total Contracted Generation or net Demand for that zone. These are summated to create a weighted zonal average.

Nodes are weighted so that the zonal locational signals are not distorted by nodes with minimal amounts of demand and Generation, and revenues are collected in proportion to the amount of Generation and Demand at that node.

The table below hopefully illustrates the above and shows how nodal locational signals for a zone are turned into a final zonal locational tariff.

Node	LRMC	Demand	Weighted Demand	Weighted LRMC
1	1300	0	0%	0
2	1400	0	0%	0
3	1300	10	13%	162.5
4	1300	5	6%	81.25
5	1200	20	25%	300
6	1200	20	25%	300
7	1300	10	13%	162.5
8	1300	5	6%	81.25
9	1300	10	13%	162.5
10	1400	0	0%	0
		80		**1250**

The Weighted Zonal LRMC[1] is 1250. The LRMC's are calculated based on adding 1MW of Generation. They are subsequently turned into a Zonal Demand tariff by multiplying by **-1**, then by the Security Factor (1.8), then by the Expansion Constant (13.574496), with the final result divided by 1000 to turn the tariff into £/kW

I.e. 1250***-1***1.8*13.574496/1000 = -30.54

If Demand was actually Contracted Generation then the Zonal Generation tariff would be 30.54 (assuming we are calculating a tariff Peak) and not -30.54

If Embedded Generation was to connect at nodes 1, 4 and 8 this would reduce the net demand at that node. For the purposes of this example the amount of Embedded Generation is of sufficient quantity to turn demand at that node negative (i.e. Exporting).

Table 1

Baseline		
Node	LRMC	Demand
1	1400	-20
2	1500	0
3	1400	10
4	1400	-15
5	1300	20
6	1300	20
7	1400	10
8	1400	-15
9	1400	10
10	1500	0
		20

[1] Long Run Marginal Cost (LRMC) is a locational signal. Further explanation is provided on page 17

As you can see the Nodal costs for Generation (LRMC) have increased in this zone as you would expect. If you add Generation (or reduce demand) at a node, the Nodal costs are likely to increase for all nodes in that zone due to an increase in flows. Node 1,4 and Node 8 have turned into negative demand.

The underlying locational signals have increased for Generation. As Demand is the inverse of Generation when calculating the Zonal Demand tariff you would expect the Locational Demand tariff to **decrease**. The table below shows the exact opposite happens when calculating the Locational Demand tariff.

Table 2

Baseline					
Node	LRMC	Demand	Weighted Demand		
1	1400	-20	-100%	-1400	
2	1500	0	0%	0	
3	1400	10	50%	700	
4	1400	-15	-75%	-1050	
5	1300	20	100%	1300	
6	1300	20	100%	1300	
7	1400	10	50%	700	
8	1400	-15	-75%	-1050	
9	1400	10	50%	700	
10	1500	0	0%	0	
		20		**1200**	-29.32

The Zonal Demand tariff now equals -29.32

*I.e. 1200****-1*****1.8*13.574496/1000 = -29.32*

This is an **increase** from the previous tariff of -30.54. So although the locational signal for Demand has decreased (LRMC's not weighted Demand) the demand tariff has gone up.

Why does this happen? Negative Demand is shown as a Negative number. When you multiply the LRMC's by Negative Demand the mathematics turn the LRMC's negative. To create a Demand tariff the Generation LRMCs are multiplied by -1 (A negative * negative = positive).

Negative Demand therefore has the effect of increasing the Locational Demand tariff when all the signals show that it should decrease further as there is less demand and more Generation.

For 18/19 the number of forecasted Exporting GSPs at Peak has increased to such an extent that the above defect is now having a material impact on Demand tariffs. The defect is exaggerated when Total Demand for a zone decreases closer to 0. When this occurs the weighted Nodal average for a node can significantly distort the Locational Demand tariff as demand at a node can be greater than the total demand for that zone (i.e. >100%).

There is a credible scenario where the Total Demand for a zone may become negative (exporting) as highlighted in table 3. In this scenario negative demand at a node actually creates an accurate locational signal, and it is positive demand nodes which work to distort the zonal locational demand tariff. The defect therefore is not negative Demand (exporting GSPs) but nodes which Export when the zone Imports and vice versa, and the underlying tariff calculations within the Tariff part of DCLF model.

Table 3

Node	LRMC	Demand	Weighted Demand			Node	LRMC	Demand	Weighted Demand		
1	1400	-20	-25%	-350		1	1400	-20	-25%	-350	
2	1500	-20	-25%	-375		2	1500	-20	-25%	-375	
3	1400	10	13%	175		3	1400	10	13%	175	
4	1400	-15	-19%	-262.5		4	1400	-15	-19%	-262.5	
5	1300	20	25%	325		5	1300	20	25%	325	
6	1300	20	25%	325		6	1300	30	38%	487.5	
7	1400	0	0%	0		7	1400	0	0%	0	
8	1400	-15	-19%	-262.5		8	1400	-15	-19%	-262.5	
9	1400	0	0%	0		9	1400	0	0%	0	
10	1500	-20	-25%	-375		10	1500	-20	-25%	-375	
		-40		**-800**	20.16			**-30**		**-637.5**	16.07

An increase in demand decreases the demand tariff which is incorrect.

The following section shows the legal text within the CUSC.

CUSC

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

Gi	=	Generation zone
j	=	Node
$NMkm_{PS}$	=	Peak Security Wider nodal marginal km from transport model
$WNMkm_{PS}$	=	Peak Security Weighted nodal marginal km
$ZMkm_{PS}$	=	Peak Security Zonal Marginal km
Gen	=	Nodal Generation (scaled by the appropriate Peak Security Scaling factor) from the transport model

Similarly, the zonal Year Round marginal km for generation is calculated as

$$WNMkm_{jYR} = \frac{NMkm_{jYR} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{GiYR} = \sum_{j \in Gi} WNMkm_{jYR}$$

Where

$NMkm_{YR}$	=	Year Round Wider nodal marginal km from transport model
$WNMkm_{YR}$	=	Year Round Weighted nodal marginal km
$ZMkm_{YR}$	=	Year Round Zonal Marginal km
Gen	=	Nodal Generation (scaled by the appropriate Year Round Scaling factor) from the transport model

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows:

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di	=	Demand zone
Dem	=	Nodal Demand from transport model

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

We would look to make changes to this calculation within the CUSC. Please note only clause 15.40 (in Section 14) is referenced as this includes the relevant definitions of the clauses within the formulae.

Why

If the defect is not resolved Demand tariffs will not accurately reflect the costs imposed on the System by taking demand at that particular location. Where Demand tariffs do not reflect underlying costs, end users will pay more or less than what is required (if someone pays more, then someone will pay less) This creates inefficient investment signals and may go so far as to incentivises adverse behaviour to the investment signal.

The Locational signal, plus total demand at Peak determines how much revenue is required to be recovered from a particular demand zone. If the locational demand tariff increases, an increased amount of revenue is required to be recovered from that zone.

If underlying demand has not actually changed then this results in Non-Half Hourly settled meters (NHH) charges rising substantially more than Half hourly settled meters (HH) charges as NHH charges act as a Residual recovery mechanism for that zone. This explains why the forecasted NHH tariff for 18/19 rises more as a percentage change greater than HH tariffs in Zone 1.

How

If total nodal demand for a zone is positive, sum all positive demands. All Negative Demand is adjusted to 0 (zero). This creates an adjusted Total Zonal Demand. All positive demand is weighted against this new demand figure.

Baseline

Node	LRMC	Demand	Weighted Demand	Weighted LRMC	
1	1300	0	0%	0	
2	1400	0	0%	0	
3	1300	10	13%	162.5	
4	1300	5	6%	81.25	
5	1200	20	25%	300	
6	1200	20	25%	300	
7	1300	10	13%	162.5	
8	1300	5	6%	81.25	
9	1300	10	13%	162.5	
10	1400	0	0%	0	
		80		**1250**	-30.54

Baseline

Node	LRMC	Demand	Weighted Demand		
1	1400	-20	-100%	-1400	
2	1500	0	0%	0	
3	1400	10	50%	700	
4	1400	-15	-75%	-1050	
5	1300	20	100%	1300	
6	1300	20	100%	1300	
7	1400	10	50%	700	
8	1400	-15	-75%	-1050	
9	1400	10	50%	700	
10	1500	0	0%	0	
		20		**1200**	-29.32

Proposed

Baseline

Node	LRMC	Demand	Weighted Demand	Weighted LRMC	
1	1300	0	0%	0	
2	1400	0	0%	0	
3	1300	10	13%	162.5	
4	1300	5	6%	81.25	
5	1200	20	25%	300	
6	1200	20	25%	300	
7	1300	10	13%	162.5	
8	1300	5	6%	81.25	
9	1300	10	13%	162.5	
10	1400	0	0%	0	
		80		**1250**	-30.54

Proposal

Node	LRMC	Original Demand	Adjusted Demand	Weighted Demand		
1	1400	-20	0	0%	0.00	
2	1500	0	0	0%	0.00	
3	1400	10	10	13%	186.67	
4	1400	5	5	7%	93.33	
5	1300	20	20	27%	346.67	
6	1300	20	20	27%	346.67	
7	1400	10	10	13%	186.67	
8	1400	-15	0	0%	0.00	
9	1400	10	10	13%	186.67	
10	1500	0	0	0%	0.00	
		40	**75**		**1346.67**	-32.9

The change in the locational zonal demand tariff now reflects changes in the underlying locational demand signal (i.e. in the correct direction)

5 Proposer's solution

Section 5 (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 7 of the Workgroup contains the discussion by the Workgroup on the Proposal and the potential solution.

If total nodal demand for a zone is positive, sum all positive demands. All Negative Demand is adjusted to 0. This creates an adjusted Total Zonal Demand. All positive demand is weighted against this new demand figure.

Baseline					
Node	LRMC	Demand	Weighted Demand	Weighted LRMC	
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6	1200	20	25%	300	
7	1300	10	13%	162.5	
8	1300	5	6%	81.25	
9	1300	10	13%	162.5	
10	1400	0	0%	0	
		80		1250	-30.54

Baseline					
Node	LRMC	Demand	Weighted Demand		
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3	1400	10	50%	700	
4	1400	-15	-75%	-1050	
5	1300	20	100%	1300	
6	1300	20	100%	1300	
7	1400	10	50%	700	
8	1400	-15	-75%	-1050	
9	1400	10	50%	700	
10	1500	0	0%	0	
		20		1200	-29.32

Proposed

Baseline					
Node	LRMC	Demand	Weighted Demand	Weighted LRMC	
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6	1200	20	25%	300	
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8	1300	5	6%	81.25	
9	1300	10	13%	162.5	
10	1400	0	0%	0	
		80		1250	-30.54

Proposal						
Node	LRMC	Original Demand	Adjusted Demand	Weighted Demand		
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4	1400	5	5	7%	93.33	
5	1300	20	20	27%	346.67	
6	1300	20	20	27%	346.67	
7	1400	10	10	13%	186.67	
8	1400	-15	0	0%	0.00	
9	1400	10	10	13%	186.67	
10	1500	0	0	0%	0.00	
		40	75		1346.67	-32.9

The change in the locational zonal demand tariff now reflects changes in the underlying locational demand signal (i.e. in the correct direction)

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

No impact observed with the TCR. Does not appear to link in with any current ongoing modifications as no mods look to change the calculation of zonal weighted demand tariffs within the tariff model. All current mods 271/274/276 are not currently under Urgent timescales.

Consumer Impacts

Consumers in the North of Scotland, if tariffs are passed through by Suppliers will see an unjustified increase in their Electricity bills. If Suppliers choose not to pass this element directly on to the end consumer i.e. (Fixed tariffs) then this will harm competition. Although the defect currently affects consumers in the North of Scotland with the growth of Embedded Generation this could feasibly affect other parts of the country i.e. South West, Wales within 5 years.

6 Urgency Request

The Proposer requested that CMP282 be treated as an urgent proposal and should not be treated as self-governance as:

- To ensure that an approved CMP282 modification is implemented in advance of the draft publication of TNUoS tariffs; and
- If the defect is not resolved Demand tariffs will not accurately reflect the costs imposed on the System by taking demand at that particular location. Where Demand tariffs do not reflect underlying costs, end users will pay more or less than what is required (if someone pays more, then someone will pay less). This creates inefficient investment signals and may go so far as to incentivises adverse behaviour to the investment signal.

The Modification should not be treated as a self-governance due to its material impact on some parties.

The CUSC Modification Panel agreed by majority that CMP282 met the criteria for urgency and as such considered that it should be treated as an Urgent CUSC Modification Proposal[2]. The Panel concluded that there was a need for Urgency is to meet the Draft publication of TNUoS tariffs, recognising that although tariffs are finalised at the end of January, Industry feedback indicates that this is a key publication.

The Authority in its urgency decision letter confirmed that urgency should **not** be granted as both the urgent and standard timetables provided to the Authority would enable the modification to be implemented, if approved, ahead of final tariff setting in January 2018. As such, we do not consider a case has been made that the modification needs to be treated urgently to address the identified defect (if appropriate), or that it will therefore have a significant commercial impact on parties, consumers or other

A copy of Ofgem's Urgency decision letter can be found in Annex 2.

[2] The CUSC Panel and Ofgem's views on Urgency for CMP282 is available using the following link: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP282/

7 Workgroup Discussions

The Workgroup convened three times to discuss the issue, detail the scope of the proposed defect, devise potential solutions, assess the proposal in terms of the CUSC Applicable Objectives and review the responses to the Workgroup Consultation.

The Proposer presented the defect that they had identified in the CMP282 proposal and highlighted that the defect related to a feature in the Tariff Model that allowed for the mathematical impact of two negatives causing a positive number.

The Proposer confirmed that whilst the defect would have been present in previous Charging Year tariffs that the issue had only become apparent and visible as the level of Embedded Generation/demand reduction had increased in certain zones.

The Workgroup explored a number of aspects in its meetings to understand the implications of the proposed defect and solutions. The discussions and views of the Workgroup are outlined below.

1. What was the cause of the defect vs. impacts on the tariff methodology

When discussing the defect and why it was only becoming apparent now all the Workgroup members were in agreement that the defect related to a feature of the Tariff Model and how the mathematics in the methodology used to calculate tariffs. Workgroup members were in agreement that the defect as described unintentionally, created a positive value when dividing two negative numbers. It was not an issue with the methodology itself which remains correct. It was the view of the Workgroup that when the methodology was introduced it was not anticipated that GSPs would be net exporting. The mathematical application results in the underlying signal not being reflective.

It was confirmed that the defect is not that there are exporting GSPs but what happens mathematically for zones that have negative demand when the Zonal Tariffs are calculated. For the avoidance of doubt it was confirmed that the LRMCs are correct.

Despite the impact of the existing calculation manifesting itself in one of the demand zones in Scotland it could materialise elsewhere where Embedded Generation/demand reduction results in the zone being a net exporter. Table 4 shows the Final tariffs for 2017/18 and forecasted tariffs for 2018/19, as published in June 2017.

Table 4

2017/18				June 2017 Forecast of 2018/19 Tariffs			
Demand				**Demand**			
Zone No.	**Zone Name**	**HH Zonal Tariff (£/kW)**	**NHH Zonal Tariff (p/kWh)**	**Zone No.**	**Zone Name**	**HH Zonal Tariff (£/kW)**	**NHH Zonal Tariff (p/kWh)**
1	Northern Scotland	29.577679	6.215608	1	Northern Scotland	52.136314	10.184611
2	Southern Scotland	30.480981	4.262747	2	Southern Scotland	33.996249	4.711528
3	Northern	39.223189	5.943493	3	Northern	43.488827	6.143092
4	North West	45.245665	5.878185	4	North West	50.229757	6.512836
5	Yorkshire	44.967107	5.978783	5	Yorkshire	49.861241	6.776159
6	N Wales & Mersey	46.791119	6.607274	6	N Wales & Mersey	51.571129	7.081867
7	East Midlands	47.889103	6.248796	7	East Midlands	52.800186	7.009019
8	Midlands	49.457444	6.426317	8	Midlands	54.548379	7.115274
9	Eastern	49.617070	7.095134	9	Eastern	54.385826	7.782534
10	South Wales	45.551887	5.775370	10	South Wales	50.953376	6.519821
11	South East	52.537577	7.475220	11	South East	57.217814	8.184488
12	London	54.969649	5.487378	12	London	59.695139	6.091993
13	Southern	53.405080	7.047920	13	Southern	58.571055	7.772624
14	South Western	51.955583	7.464813	14	South Western	58.296471	8.233390

2. Impact on previous Charging Year tariffs

The Proposer confirmed that whilst this defect had always been a feature of the calculation, prior to 2018/19 the impact was low, as exporting GSPs arose infrequently, therefore there was minimal impact on tariffs, if any. Furthermore it was confirmed that all Parties had paid the correct amount of TNUoS charges in relation to tariffs based on the agreed methodology in place however a correction in the formula under CMP282 would further improve cost reflectivity of tariffs.

3. Long Run Marginal Costs (LRMCs)

The DCLF model calculates a locational signal (LRMCs) for each node (location) on the network. The model lists against each node the nodal incremental cost of adding 1MW of **Generation.** If the LRMC is a positive number then adding 1MW of Generation at that location increases flows on the System, If it's a negative number then adding 1MW of Generation at that location decreases flows on the System i.e. the South West of England. The impact of adding 1MW of Demand is the inverse of Generation. This is why the sum of weighted demand is then multiplied by -1 (turns the locational signal from Generation to Demand). In Demand Zone 1 the Nodal Incremental costs are negative. I.e. by taking demand in Scotland, flows are reduced on the System. The defect reduces this negative signal thus increasing the final Zonal Demand Tariff (Locational plus Residual).

4. Build-up of Demand Tariffs

Zonal Demand Tariffs contain both a Locational and Residual element. Table 5 and Table 6 on the following two pages illustrate how the Final Zonal Demand Tariff for 2017/18 and 2018/19 were derived. By comparing Table 5 and Table 6 the change in the Zonal Demand Tariff for Zone 1 can be seen to originate from the large change in the locational element of the charge (the defect).

When discussing HH charges it is more obvious how the locational element affects the Final HH Demand Tariff. However, by following through the table you can see how the locational element flows through to the Zonal NHH tariff as well.

The purpose of these tables is therefore twofold. Firstly to illustrate how charges are derived, and secondly to show how the defect manifests itself in the final tariff. It is the result of the locational element solely and no other components (e.g. changes such as demand forecasts etc.).

Table 5

TARIFFS 2017/18

Derivation of Zonal Demand HH Tariffs - Peak Secu						Year Round					Final HH Demand Tariffs	
Zone	Zone Name	Total Demand Charge Base: Triad Demand (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Peak Security Transport Zonal Tariff (£/kW)	Peak Security Transport Zonal Revenue (£m)	Year Round Unadjusted Zonal Wtd Marginal (km)	Year Round Transport Zonal Tariff (£/kW)	Year Round Transport Zonal Revenue (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	0.923	-76.64	1.87	1.73	822.95	-20.11	-18.57	47.26	43.64	29.03	26.80
2	Southern Scotland	3.109	-0.92	0.02	0.07	710.26	-17.35	-53.96	47.26	146.94	29.93	93.05
3	Northern	2.267	109.32	-2.67	-6.06	242.23	-5.92	-13.42	47.26	107.14	38.67	87.67
4	North West	3.854	29.20	-0.71	-2.75	75.87	-1.85	-7.14	47.26	182.14	44.69	172.25
5	Yorkshire	3.566	105.43	-2.58	-9.19	11.04	-0.27	-0.96	47.26	168.52	44.41	158.37
6	N Wales & Mersey	2.350	74.35	-1.82	-4.27	-32.53	0.79	1.87	47.26	111.06	46.24	108.66
7	East Midlands	4.360	87.18	-2.13	-9.29	-90.30	2.21	9.62	47.26	206.06	47.34	206.39
8	Midlands	4.125	57.72	-1.41	-5.82	-125.02	3.05	12.60	47.26	194.93	48.91	201.71
9	Eastern	6.036	-42.63	1.04	6.29	-31.20	0.76	4.60	47.26	285.26	49.06	296.15
10	South Wales	1.657	253.13	-6.19	-10.25	-160.60	3.92	6.50	47.26	78.29	45.00	74.54
11	South East	3.711	-157.88	3.86	14.32	-35.48	0.87	3.22	47.26	175.39	51.99	192.93
12	London	4.112	-206.46	5.04	20.74	-86.43	2.11	8.68	47.26	194.32	54.42	223.75
13	Southern	5.179	-68.74	1.68	8.70	-160.13	3.91	20.27	47.26	244.78	52.85	273.75
14	South Western	2.436	38.22	-0.93	-2.27	-207.76	5.08	12.36	47.26	115.11	51.40	125.20
		47.684			**1.96**			**-14.33**		**2,253.60**		**2,241.23**

Derivation of Capped Zonal Demand NHH Tariffs									
Zone	Zone Name	Total Demand Charge Base: Triad Demand (MW)	Chargeable HH Zonal Triad Demand (MW)	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share (%)	NHH Zonal Tariff (p/kWh)
1	Northern Scotland	923.39	- 668.025	-19.39	1,591.42	46.19	0.75	3%	6.14
2	Southern Scotland	3,109.18	641.726	19.21	2,467.45	73.85	1.76	7%	4.19
3	Northern	2,266.99	314.289	12.15	1,952.71	75.51	1.29	5%	5.87
4	North West	3,853.96	1,174.622	52.50	2,679.33	119.75	2.06	8%	5.80
5	Yorkshire	3,565.78	1,106.638	49.15	2,459.14	109.22	1.85	7%	5.90
6	N Wales & Mersey	2,349.89	519.724	24.03	1,830.17	84.62	1.30	5%	6.53
7	East Midlands	4,360.13	1,456.313	68.94	2,903.82	137.46	2.23	9%	6.17
8	Midlands	4,124.58	1,400.271	68.48	2,724.31	133.23	2.10	8%	6.35
9	Eastern	6,035.90	1,472.861	72.27	4,563.04	223.88	3.19	13%	7.02
10	South Wales	1,656.54	554.199	24.94	1,102.34	49.60	0.87	3%	5.70
11	South East	3,711.20	870.404	45.25	2,840.79	147.68	2.00	8%	7.40
12	London	4,111.70	2,194.260	119.41	1,917.44	104.34	1.93	8%	5.41
13	Southern	5,179.46	1,649.598	87.19	3,529.86	186.56	2.68	11%	6.97
14	South Western	2,435.66	540.175	27.77	1,895.49	97.43	1.32	5%	7.39
		47,684.35	**13,227.05**	**651.88**	**34,457.30**	**1,589.35**	**25.31**		

Table 6

2018/19 June Forecast

Derivation						Year Round					Final HH	
Zone	Zone Name	Total Charge Base: Triad (GW)	Peak Security Unadjusted Zonal Wtd Marginal (km)	Peak Security Transport Zonal Tariff (£/kW)	Peak Security Transport Zonal Revenue (£m)	Year Round Unadjusted Zonal Wtd Marginal (km)	Year Round Transport Zonal Tariff (£/kW)	Year Round Transport Zonal Revenue (£m)	Residual Tariff (£/kW)	Residual Zonal (£m)	Final Zonal Tariff (£/kW)	Final Zonal Revenue Recovery (£m)
1	Northern Scotland	0.928	-214.08	5.43	5.04	248.66	-6.30	-5.85	52.20	48.44	51.33	47.63
2	Southern Scotland	2.999	14.25	-0.36	-1.08	735.75	-18.66	-55.94	52.20	156.55	33.19	99.52
3	Northern	2.241	111.82	-2.84	-6.35	263.80	-6.69	-14.99	52.20	116.98	42.68	95.64
4	North West	3.685	25.76	-0.65	-2.41	84.01	-2.13	-7.85	52.20	192.36	49.42	182.11
5	Yorkshire	3.395	99.05	-2.51	-8.53	25.25	-0.64	-2.17	52.20	177.24	49.05	166.54
6	N Wales & Mersey	2.281	75.63	-1.92	-4.37	-18.77	0.48	1.09	52.20	119.07	50.76	115.78
7	East Midlands	4.228	82.62	-2.09	-8.86	-74.23	1.88	7.96	52.20	220.75	51.99	219.85
8	Midlands	3.960	49.26	-1.25	-4.95	-109.82	2.78	11.03	52.20	206.72	53.74	212.80
9	Eastern	5.829	-42.69	1.08	6.31	-11.45	0.29	1.69	52.20	304.32	53.58	312.32
10	South Wales	1.592	239.82	-6.08	-9.68	-158.59	4.02	6.40	52.20	83.08	50.14	79.81
11	South East	3.579	-139.68	3.54	12.68	-26.16	0.66	2.37	52.20	186.86	56.41	201.91
12	London	3.918	-199.64	5.06	19.83	-63.90	1.62	6.35	52.20	204.53	58.89	230.71
13	Southern	5.014	-70.18	1.78	8.92	-149.03	3.78	18.95	52.20	261.76	57.76	289.63
14	South Western	2.355	11.12	-0.28	-0.66	-219.50	5.57	13.11	52.20	122.95	57.49	135.39
		46.004			**5.89**			**-17.87**		**2,401.62**		**2,389.64**

Derivation									
Zone	Zone Name	Total Charge Base: Triad (MW)	Chargeable HH Zonal Triad	HH Zonal Triad Demand Revenue Recovery (£m)	Residual NHH Zonal Triad Demand (MW)	Required NHH Zonal Revenue Recovery (£m)	NHH Zonal 1600-1900 Demand (TWh)	NHH Zonal 1600-1900 Demand Share	NHH Zonal Tariff
1	Northern Scotland	927.92	- 530.025	-27.21	1,457.94	74.83	0.742763	3%	10.07
2	Southern Scotland	2,998.82	662.008	21.97	2,336.81	77.55	1.685257	7%	4.60
3	Northern	2,240.74	525.800	22.44	1,714.94	73.19	1.213144	5%	6.03
4	North West	3,684.81	1,166.911	57.67	2,517.90	124.44	1.943373	8%	6.40
5	Yorkshire	3,395.16	1,006.692	49.38	2,388.47	117.16	1.757455	7%	6.67
6	N Wales & Mersey	2,280.76	593.761	30.14	1,687.00	85.64	1.228252	5%	6.97
7	East Midlands	4,228.48	1,375.947	71.54	2,852.53	148.31	2.149586	9%	6.90
8	Midlands	3,959.84	1,353.543	72.74	2,606.30	140.06	1.999284	8%	7.01
9	Eastern	5,829.32	1,428.604	76.54	4,400.72	235.78	3.072886	13%	7.67
10	South Wales	1,591.52	526.254	26.39	1,065.27	53.42	0.833327	3%	6.41
11	South East	3,579.44	837.950	47.27	2,741.49	154.65	1.915153	8%	8.07
12	London	3,917.87	2,068.436	121.80	1,849.43	108.91	1.820474	8%	5.98
13	Southern	5,014.20	1,617.342	93.42	3,396.85	196.21	2.560509	11%	7.66
14	South Western	2,355.17	553.505	31.82	1,801.66	103.57	1.274955	5%	8.12
		46,004.03	**13,186.73**	**695.92**	**32,817.30**	**1,693.72**	**24.196417**		

5. Historic Tariffs

The Workgroup noted that the defect has always been within the Zonal Tariff calculation and queried why it had only been detected in forecast tariffs for 2018/19 (Demand Zone 1) and only had very minimal effect on tariffs in previous charging years. The National Grid representative explained the process of inputting data into the DCLF which calculates locational prices, and in particular Wk24 demand data. Each DNO provides National Grid a forecast of net demand at each Grid Supply Point (GSP) within their Distribution Network at System Peak (i.e. at the time of maximum demand on the GB System). This demand data is commonly known as Wk24 Demand data as it is received around Wk24 of the calendar year.

Wk24 Demand data is not provided by DNO's to National Grid for the purposes of setting locational tariffs. Its main purpose is for System Planning. However Wk24 demand data is an independent forecast of demand so it is used to set locational tariffs.

When comparing the forecasts of demand in Zone 1 for 2018/19 against 2017/18 a 50% increase in Exporting GSPs was noted resulting in a negative weighted demand for that node when calculating the Zonal Locational Demand tariff. As described earlier in the report a negative weighted demand value for a node distorts the locational signal.

The increase in Exporting GSPs is due to several factors such as new Embedded Generation, assessments of existing Generators output at Peak, as well as Demand Reductions.

As Total zonal demand reduces near to 0 (zero) and Embedded Generation increases, the weighted impact of negative demand also increases. This, coupled with larger LRMCs, (as demand reduces and Generation increases) amplifies the effect of the defect in Zone 1. Figures 1 to 3 show the effect of; increasing number of Exporting GSPs, Decreasing Total Demand within a zone, and changing LRMC's. Figure 4 shows the effect on the locational demand tariff when all 3 combine. These examples highlight why the defect is now starting to have a material impact on tariffs. Table 8 shows the effect on 2017/18 tariffs if the original proposal had been implemented for that charging year (2017/18).

Please remember that the examples illustrate simply Demand Zone 1 where the locational signal is negative. A reduced negative signal will increase the Final Zonal Demand tariff.

Figure 1 Increasing Exporting GSPs

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	50	150	0.125	18.75
2	100	50	0.25	12.5
3	50	100	0.125	12.5
4	0	200	0	0
5	200	100	0.5	50
	400			**93.75**
		Locational Demand		-93.75

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75
2	150	50	0.375	18.75
3	100	100	0.25	25
4	-50	200	-0.125	-25
5	250	100	0.625	62.5
	400			**62.5**
		Locational Demand		-62.5

Figure 2 Decreasing Demand

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC		Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75		1	-50	150	-0.125	-18.75
2	150	50	0.375	18.75		2	100	50	0.25	12.5
3	100	100	0.25	25		3	50	100	0.125	12.5
4	-50	200	-0.125	-25		4	-50	200	-0.125	-25
5	250	100	0.625	62.5		5	150	100	0.375	37.5
	400			**62.5**			**200**			**18.75**
		Locational Demand		-62.5				**Locational Demand**		-18.75

Figure 3 Changing Locational Signals

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC		Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75		1	-50	200	-0.125	-25
2	150	50	0.375	18.75		2	150	50	0.375	18.75
3	100	100	0.25	25		3	100	100	0.25	25
4	-50	200	-0.125	-25		4	-50	250	-0.125	-31.25
5	250	100	0.625	62.5		5	250	100	0.625	62.5
	400			**62.5**			**400**			**50**
		Locational Demand		-62.5				**Locational Demand**		-50

Figure 4 Combination of all 3

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC		Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	150	-0.125	-18.75		1	-50	200	-0.125	-25
2	150	50	0.375	18.75		2	100	50	0.25	12.5
3	100	100	0.25	25		3	50	100	0.125	12.5
4	-50	200	-0.125	-25		4	-50	250	-0.125	-31.25
5	250	100	0.625	62.5		5	150	100	0.375	37.5
	400			**62.5**			**200**			**6.25**
		Locational Demand		-62.5				**Locational Demand**		-6.25

Table 8 shows the change in the locational element of 2017/18 tariffs if the Original Proposal had been in place. The change in locational tariffs for 2017/18 is a lot less pronounced than the change in 2018/19 tariffs between baseline and the original proposal.

As explained in the figures above the defect has been amplified for 2018/19 and is now a material defect. When assessing changes to tariffs, as part of the forecasting and tariff setting procress, it is very difficult to assess what the magnitude of change should be. Small changes in Contracted Generation or Demand at a node, can lead to large changes in tariffs, especially if circuits are lightly loaded and change the direction of flow; and vice versa; large changes in input data do not always cause large changes in tariffs. Therefore the direction of change is often used as an important sense check and validation step rather than just assessing the magnitude. When comparing 2017/18 tariffs to 2016/17, the direction of change for zone 1 was in the same direction as all other zones. When comparing Zone 1 2017/18 to 2018/19 (Baseline), Zone 1's final Zonal Demand tariff goes in completely the opposite direction as all other zones, and in a different direction to the underlying locational signals.

6. Solutions

This section looks at the Proposers solution and other potential options to resolve the defect.

Proposer’s solution: setting all negative demand to zero

The Proposer explained that having reviewed the output from the Transport model the negative demand in Scotland has the impact of increasing the locational tariff in the opposite direction to the indicated underling locational signals: When demand decreases in a zone or Generation increases this increases the Generation LRMCs. This therefore should decrease Demand LRMC’s. This proposal therefore looks to treat negative demand nodes differently.

When calculating the Zonal Locational Tariff the calculation ignores negative demand (Exporting GSPs). As you can see this corrects the distortion in the locational signal.

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC		Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25		1	0	200	0	0
2	100	50	0.25	12.5		2	100	50	0.25	12.5
3	50	100	0.125	12.5		3	50	100	0.125	12.5
4	-50	250	-0.125	-31.25		4	0	250	0	0
5	150	100	0.375	37.5		5	150	100	0.375	37.5
	200			**6.25**			**300**			**62.5**
		Locational Demand		-6.25				**Locational Demand**		-62.5

The Proposer confirmed that the solution would set any BMUs that have a negative demand to zero to ensure the correct locational signal. A demand node is a summation of all BMUs mapped to that GSP.

The view of the Workgroup was that the Proposer’s original solution, if implemented, would prevent the locational signal being diluted further by setting negative values to zero when calculating the tariffs.

The Workgroup Proposer noted that the merits of this solution was its simplicity. It ensures negative values do not impact the final tariff rather than manipulating data such as changing an Exporting Node to an Importing. Demand Nodes are weighted so that the Zonal Demand tariff is in proportion to the nodes creating the signal and the revenue then subsequently received is also in the same proportion. Exporting GSP’s do not pay Demand tariffs therefore should not be included in the Zonal Demand tariff calculation.

The Workgroup then explored other options.

Option 1 Absolute Demand

All demand is treated as positive, so Exporting GSPs are turned into an Importing Node.

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25
2	100	50	0.25	12.5
3	50	100	0.125	12.5
4	-50	250	-0.125	-31.25
5	150	100	0.375	37.5
	200			**6.25**
		Locational Demand		-6.25

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	50	200	0.125	25
2	100	50	0.25	12.5
3	50	100	0.125	12.5
4	50	250	0.125	31.25
5	150	100	0.375	37.5
	400			**118.75**
		Locational Demand		-118.75

The Workgroup noted that this proposal solved the defect but achieved this by treating an exporting node and Importing. This was seen as manipulating data for the purposes of solving the defect, which was not justifiable. Under this solution the locational signal reduced significantly which results in the sum of the locational plus residual elements of the Final Zonal Tariff being less than 0. This would lead to the Demand Tariff for this zone being rebased to 0 (zero) as Demand Tariffs cannot be negative. Despite the merits of this option which would be simple to implement and would include all locational signals for demand, this option was not considered credible

Option 2 Absolute Weighted Demand

The Workgroup and the Proposer considered whether the defect could be resolved by making all the weighted demand absolute (making all the negative demands into positive demand).

All weighted demand is treated as positive, so Exporting GSPs LRMC's are essentially turned into an Importing Node.

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	-0.125	-25
2	100	50	0.25	12.5
3	50	100	0.125	12.5
4	-50	250	-0.125	-31.25
5	150	100	0.375	37.5
	200			**6.25**
		Locational Demand		-6.25

Nodes	Demand	LRMC	Weighted Demand	Weighted LRMC
1	-50	200	0.125	25
2	100	50	0.25	12.5
3	50	100	0.125	12.5
4	-50	250	0.125	31.25
5	150	100	0.375	37.5
	200			**118.75**
		Locational Demand		-118.75

As noted in Option 1 this option would involve manipulating data and not deemed an acceptable manner in resolving the defect. It would however resolve the defect and the locational tariffs would be more in line with the original proposal. The merits of this option are its simplicity to implement and include all locational signals for demand.

Option 3 Treat Exporting GSPs as Generation

The Workgroup noted that whilst the Proposer's original solution was the most pragmatic approach for resolving the demand tariff aspect that at a future date consideration should be made to investigate the generation tariffs.

Use of Gross Demand

In this option the Workgroup and the Proposer considered whether the defect could be resolved by using gross demand e.g. partially splitting Embedded Generation from demand. The view of the Workgroup was that this would have the advantage of solving the defect but ensuring that all locational signals for a zone Exporting and Importing are taken into account in either an Exporting (Generation) or Importing tariff (Demand).

However. the major obstacle in pursuing this option was how to treat Exporting nodes in terms of scaling. All Generation is currently scaled according to the SQSS. There are currently no rules regarding how to scale Embedded Generation. The Workgroup noted that this issue is being explored under the SQSS and that once the outcome of the work of the GSR16 Workgroup was known, that another modification similar to CMP282 might be raised. In terms of timescales this is likely to be another year at least before any new rules are put in place. The defect is in place for 2018/19 so it is not appropriate to wait for other industry processes to run their course before trying to solve this defect.

7. Impact on tariffs for the Charging Year 2018/2019 (should the CMP282 Original be implemented) and materiality implications

The Workgroup as part of its analysis was presented with information on what the impacts would be on the 2018/2019 demand tariffs if the CMP282 original proposal was implemented.

In terms of the locational part of the Demand Tariff this will only change if the Demand Zone records any Exporting GSPs. Those Demand Zones will see a reduction in the Locational Tariff and a subsequent reduction in the revenue required to be recovered from that zone.

Because less revenue is recovered this will have an impact on the Demand Residual, which will affect all Demand Zones.

Because the Demand Residual changes this also has a knock-on effect on the Small Generators Discount as this is based on 25% of the Demand and Generation Residuals.

This is highlighted in Table 7 on the following page. Demand Zones with no Exporting GSPs should only see a change equivalent to the change in the Residual and Small Generators Discount.

NHH Tariffs will alter slightly differently between zones due to how NHH are set (i.e. residual Recovery).

Table 7

	June Forecast		Original Proposal				Absolute Demand				Absolute Weighted Demand			
Zone	HH	*NHH*	HH	**Change to June**	*NHH*	***Change to June***	HH	**Change to June**	*NHH*	***Change to June***	HH	**Change to June**	*NHH*	***Change to June***
1	52.14	*10.18*	29.01	-23.13	*5.64*	*-4.54*	25.42	-26.72	*4.94*	*-5.24*	-123.82	-175.96	*-24.36*	*-34.54*
2	34.00	*4.71*	34.24	0.25	*4.75*	*0.03*	34.11	0.11	*4.73*	*0.02*	35.05	1.05	*4.86*	*0.15*
3	43.49	*6.14*	43.97	0.48	*6.21*	*0.07*	44.04	0.55	*6.22*	*0.08*	45.99	2.50	*6.50*	*0.35*
4	50.23	*6.51*	50.60	0.37	*6.56*	*0.05*	50.56	0.33	*6.56*	*0.04*	53.69	3.46	*6.96*	*0.45*
5	49.86	*6.78*	50.38	0.52	*6.85*	*0.07*	50.48	0.62	*6.86*	*0.08*	53.86	4.00	*7.32*	*0.54*
6	51.57	*7.08*	52.09	0.52	*7.15*	*0.07*	52.19	0.62	*7.17*	*0.09*	55.57	4.00	*7.63*	*0.55*
7	52.80	*7.01*	53.32	0.52	*7.08*	*0.07*	53.42	0.62	*7.09*	*0.08*	56.80	4.00	*7.54*	*0.53*
8	54.55	*7.12*	55.06	0.52	*7.18*	*0.07*	55.17	0.62	*7.20*	*0.08*	58.55	4.00	*7.64*	*0.52*
9	54.39	*7.78*	54.90	0.52	*7.86*	*0.07*	55.01	0.62	*7.87*	*0.09*	58.38	4.00	*8.35*	*0.57*
10	50.95	*6.52*	51.47	0.52	*6.59*	*0.07*	51.57	0.62	*6.60*	*0.08*	54.95	4.00	*7.03*	*0.51*
11	57.22	*8.18*	57.73	0.52	*8.26*	*0.07*	57.84	0.62	*8.27*	*0.09*	61.21	4.00	*8.76*	*0.57*
12	59.70	*6.09*	60.21	0.52	*6.14*	*0.05*	60.31	0.62	*6.16*	*0.06*	63.69	4.00	*6.50*	*0.41*
13	58.57	*7.77*	59.09	0.52	*7.84*	*0.07*	59.19	0.62	*7.85*	*0.08*	62.57	4.00	*8.30*	*0.53*
14	58.30	*8.23*	58.81	0.52	*8.31*	*0.07*	58.92	0.62	*8.32*	*0.09*	62.29	4.00	*8.80*	*0.56*
Small Gens	0.81	*0.11*	0.82	0.01	*0.11*	*0.00*	0.82	0.01	*0.11*	*0.00*	0.87	0.06	*0.12*	*0.01*
Residual	52.20		52.71	0.51			52.82	0.61			56.14	3.94		

8. Impact on previous tariffs had CMP282 been approved and implemented

The Workgroup consider what the impacts would have been on previous tariffs had CMP282 Original Proposal (setting negative demand to zero) been approved and implemented. Table 8 shows the locational element of the tariff if the Original Proposal had been implemented in 2017/18.

Table 8

Original Tariffs 17/18					17/18 Tariffs if Original Proposal Used				
Residual	47.26				Residual	47.33			
Zone	**Zonal Total**	**Total Zonal HH Tariff (£/kW)**	**Zonal Demand**	**Revenue Recovery £m**	**Zone**	**Zonal Total**	**Total Zonal HH Tariff (£/kW)**	**Revenue Recovery £m**	**Difference £m**
1	-18.24	29.02	0.92	26.80	**1**	-21.71	25.62	23.66	3.14
2	-17.33	29.93	3.11	93.05	**2**	-17.39	29.94	93.10	-0.05
3	-8.59	38.67	2.27	87.67	**3**	-8.61	38.72	87.78	-0.12
4	-2.57	44.69	3.85	172.24	**4**	-2.57	44.77	172.52	-0.28
5	-2.85	44.41	3.57	158.37	**5**	-2.85	44.49	158.63	-0.26
6	-1.02	46.24	2.35	108.65	**6**	-1.02	46.31	108.83	-0.17
7	0.08	47.34	4.36	206.39	**7**	0.08	47.41	206.71	-0.32
8	1.64	48.90	4.12	201.71	**8**	1.64	48.98	202.01	-0.30
9	1.80	49.06	6.04	296.15	**9**	1.80	49.14	296.58	-0.44
10	-2.26	45.00	1.66	74.54	**10**	-2.26	45.07	74.66	-0.12
11	4.72	51.98	3.71	192.92	**11**	4.72	52.06	193.19	-0.27
12	7.16	54.42	4.11	223.74	**12**	7.16	54.49	224.04	-0.30
13	5.59	52.85	5.18	273.74	**13**	5.59	52.92	274.12	-0.38
14	4.14	51.40	2.44	125.20	**14**	4.14	51.48	125.38	-0.18

The Table above shows the change in Zonal Revenue Recovery for 2017/18 if the original proposal had been implemented for that charging year. Zonal Revenue Recovery would have been £3m less for 2017/18 based on forecasted demand. For previous years, the amount would have been less. This is because the defect which is being addressed by this proposal increases in magnitude as the number of Exporting Grid Supply Points at peak increases and Total Zonal demand within a zone decreases. There has been a steady year on year increase in Exporting Grid Supply points and reduction in Total Zonal demand therefore the difference of £3m will be less.

Table 9 shows the change in the 2018/19 Locational element of the tariff for the February forecast of tariffs and the Original Proposal for this change. The change in the locational element of the charge is far more pronounced than 2017/18.

Table 9

1819 Tariffs Baseline			1819 Tariffs Original		
Year Round	Peak	Zonal Total	Year Round	Peak	Zonal Total
-7.55	2.03	-5.51	-25.52	-1.22	-26.73
-18.65	-1.55	-20.20	-18.76	-1.64	-20.40
-6.41	-3.12	-9.53	-6.39	-3.17	-9.55
-1.99	-0.84	-2.83	-2.12	-0.86	-2.98
-0.44	-2.51	-2.95	-0.44	-2.51	-2.95
0.58	-2.12	-1.54	0.58	-2.12	-1.54
1.94	-1.65	0.29	1.94	-1.65	0.29
2.97	-1.41	1.56	2.97	-1.41	1.56
0.38	1.63	2.01	0.38	1.63	2.01
3.79	-5.99	-2.20	3.79	-5.99	-2.20
0.60	3.69	4.29	0.60	3.69	4.29
1.68	5.38	7.06	1.68	5.38	7.06
3.57	1.83	5.40	3.57	1.83	5.40
4.73	-0.84	3.89	4.73	-0.84	3.89

9. Workgroup evaluation of potential options

The examples are simple to implement apart from Gross Charging. The Workgroup was provided a spreadsheet showing how the potential options would work in practice and the effect on Locational Tariffs. The overall effect on tariffs is shown in Table 7.

10. Potential Options 1 and 2

All members of the Workgroup agreed that although these potential options achieved the correct result in reducing the Locational Demand tariff this was achieved by treating Exporting Nodes as Importing which was clearly not the correct thing to do, so was correcting one distortion by introducing a new one.

11. Option 3

Option 3 does exactly the same as the Original Proposal but goes one step further by not ignoring Exporting GSPs and including them in the calculation of Zonal Generation Locational Tariffs. A number of Workgroup members said that this seemed a sensible approach in general. However they had a number of concerns with the approach of simply moving Exporting Demand and treating it as Generation.

12. Scaling

The Generation numbers in the Transport Model have firstly been scaled according to SQSS rules to match demand. By simply moving across a number from Demand and inserting in Generation, treats this Generation differently from other Generation types which, is discriminatory. The figures of -50 as shown in figure 2 may be made up of a number of different Generation types, which would need to be scaled differently according to their Generation type. This proposal treats all Embedded Generation the same.

Another Workgroup member commented that the number -50 is a net figure but may actually be made up of 100 units Embedded Generation and 50 units of demand so by moving across Exporting GSPs you are ignoring Embedded Generation at other nodes on the System which may not have negative demand.

The Workgroup proposer was asked the question on how granular Wk24 Demand data is. The proposer stated that the DNO's are accurate in providing net demand figures as this can be taken from metering at the GSP, and this is the number used in the DCLF model. They do provide a number showing connected Generation at Peak. However the proposer did not feel that this number as well as Gross demand was of sufficient quality to set cost reflective charges. However they noted that they felt the accuracy of this number was improving year on year but this was a purely subjective point of view.

Workgroup members noted that there is an open SQSS modification GSR016, which is currently investigating how to scale Embedded Generation.

13. Future Work

This modification coupled with BSC Modifications P348 and P349 which will split Exporting and Importing meters within a Distribution zone will provide more data and set rules on how to deal with Embedded Generation. The Workgroup noted that when these modifications are complete then Option 3 may well be a more enduring solution.

14. Conclusion

It was agreed by the Workgroup that the defect does need to be resolved but that a pragmatic solution that resolves the defect and is simple and quick to implement should be the aim of the Workgroup. Changing Exporting demand to Importing (Options 2 & 3) was manipulating data for the sole purpose of resolving a defect and as such was discounted by the Workgroup.

It was the view of the Workgroup that the CMP282 Original Proposal would on balance, be the only acceptable solution. The Workgroup did note that the baseline should be re-assessed as and when data and rules are in place to allow a more complete solution.

15. Impacts on Suppliers and Supplier tariffs

In considering how CMP282 could work, the Workgroup discussed what the impacts would be on setting the 2018/2019 demand tariffs and how these would be used by Suppliers in setting their tariffs. It was confirmed by the Workgroup that the original CMP282 provided a practical solution to allow for a decision by Ofgem to be made in time for the publication of draft tariffs.

16. Transitional Arrangements

The modification is intended to be fully implemented and not phased in. Demand Tariffs in Zone 1 are materially impacted for 2018/19. Making the required changes does have a consequential impact on all other demand zones through an increased residual value. Due to the relatively small size of Demand Zone 1 compared to other Demand zones the change in the residual is within the magnitude of change between Quarterly Forecasts of tariffs. As there is only one option for this proposed modification parties are able to more easily assess the impact and take appropriate risks into consideration when forecasting tariffs for the 2018/19 charging year.

17. Legal text changes

The Workgroup discussed at a high level what the changes could be to Section 14 of the CUSC. The legal text changes are included in Section 8.

8 Workgroup Consultation responses

The CMP282 Workgroup sought 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 summarised below:

The CMP282 Workgroup Consultation was issued on 1 August 2017 for 10 Working Days, with a close date of 14 August 2017. No addition questions to the standard Workgroup consultation questions were asked.

Six responses were received to the Workgroup Consultation and are detailed in table 10 below.

The Workgroup discussed the responses received and noted the following for the Uniper and Highland & Island Enterprises responses.

Uniper Response:

The Proposer wanted to note that the suggestion in the response in terms of amending the original proposal has merit and deserved further consideration which was undertaken. The amendment suggested was initially considered as being part of the original solution when the modification was first raised. When the Total Demand for a zone turns negative Exporting nodes and not Importing Nodes accurately reflect the underlying locational signals.

After reviewing all Demand Zones in the recent five year forecast, if Exporting nodes were turned to 0 values (as per the original solution), the Total Demand in those Zones would all be positive (Importing). The result of this analysis shows that the original solution works even when Total Demand in a zone initially goes negative and the solution is enduring. In fact there would only be the need to change the solution if there were no Importing nodes at all within a zone, which is not a credible scenario. Workgroup members also stated that Demand Zone tariffs should be calculated and based on Importing Nodes and not Exporting Nodes.

Highland and Island Enterprise Response:

The Proposer replied directly to the originator of the Highland and Island Enterprise response explaining in detail how the defect was initially discovered and the process and actions which were subsequently undertaken to raise a modification and the timelines involved. The Proposer noted that they do endeavour to spot defects before they become material and try and be less reactive. In this case a step change in demand forecasts highlighted the defect which had not been apparent in other long term forecasts. In response to a question of whether or not end consumers will have been affected by the defect the proposer explained that the Workgroup had examined historic tariffs and found that the defect only materially manifested in the February forecast 2017 of 2018/19 tariffs. The proposer also stated that it was highly unlikely that the forecasted tariff in February 2017 would have made it into end consumers bills due to the fact that it was an obvious outlier compared to previous tariffs. Suppliers within the Workgroup also confirmed that it is highly unlikely that end consumers will have being affected due to the timing of the forecast and the obvious ‘Error’ in Demand Zone 1.

HIE would like some assurance that any change originating from this modification benefits the end consumer. This could potentially be achieved by Ofgem stating that consumers’ tariffs should reflect suppliers liability following any modification change. The proposer stated that National Grid is actively looking at ways to keep all materially affected parties informed of modifications which may affect them.

Table 10: Workgroup Consultation Responses

Response from	Q1: Do you believe that CMP282 Original proposal or either of the potential options for change 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?
Paul Jones, Uniper	Yes, the original appears the best solution on balance subject to the suggested change in the answer to question 3 below.	Yes	Given that there is a credible scenario that at some point the demand as a whole for a zone could be negative, we would suggest that the solution should also seek to set positive demand nodes to zero in these circumstances, in order to avoid a similar issue. This would futureproof the proposal avoiding the need for a subsequent, presumably urgent, modification.	We do not wish to raise a consultation alternative, but believe that the proposer and/or Workgroup should consider altering the original proposal in order to make the small adjustment as suggested under question 3 above.
James Anderson, Scottish Power	We agree that there is a defect in the current charging methodology which results in inaccurate zonal locational signals where there are exporting GSPs (nodes) within a demand TNUoS charging zone. The original proposal addresses this defect by setting all negative demand nodes to zero when calculating he zonal tariff. By addressing the defect, the original	We agree that the proposal should be implemented in a timescale which will remove the defect from 2018/19 tariffs	No	No

Response from	Q1: Do you believe that CMP282 Original proposal or either of the potential options for change 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?
	proposal provides tariffs which are more reflective of the costs imposed on the system by users on the system when changing demand within a TNUoS charging zone (Applicable Charging Objective (ACO) (b)). By providing a more cost reflective demand charging signal, the original proposal better facilitates competition (ACO (a)) The proposal is neutral against the other ACOs. The alternative proposals (absolute demand, absolute weighted demand and treating exporting GSPs as generation) involve manipulation of the charging data which creates further distortions and therefore do not facilitate the applicable charging objectives better than the current baseline.			
Karl Maryon, Haven Power	We believe the CMP282 original proposal which seeks to amend how the DCLF model calculates Zonal Locational Demand tariffs better facilitates the CUSC objective (b) because under this proposal the final locational zonal demand tariffs accurately	Yes	No	No

Response from	Q1: Do you believe that CMP282 Original proposal or either of the potential options for change 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?
	reflect the underlying locational signals. We are against options 1 and 2 as we do not believe they facilitate CUSC objective (b). Both involve proposals which could be seen as manipulating data for the purpose of solving the defect. We believe the extended timescales required for implementation rule out option 3 at this time.			
Binoy Dharsi, EDF	We have assessed the original proposal against each of the applicable CUSC objectives and have expanded more of our reasons in the commentary below. Objective a) Neutral Objective b) We agree that it results in a most cost reflective methodology Objective c) Neutral Objective d) Neutral Objective e) We agree it meets the requirement in the implementation and	Yes. We believe due to the materiality on 2018/19 TNUoS tariffs Ofgem should make their determination in time for National Grid to reflect this in the publication of draft tariffs (due late December 2017).	The Workgroup was not tasked with evaluating other potential defects that could arise in the charging model due to increases in embedded generation. This is perhaps something that could be explored separately by National Grid? This will potentially avoid instances where charging reform is need at such short notice.	We do not wish to raise any alternatives.

Response from	Q1: Do you believe that CMP282 Original proposal or either of the potential options for change 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?
	administration of the CUSC arrangements by directly and clearly rectifying an obvious defect. CMP282's sole purpose is to correct a formula that was not originally configured to handle the impact that nodes connected to a DNO that export power onto the Grid are having on the locational signal in a particular demand zone. Prior to 2016/17 TNUoS tariffs there have only been demand nodes importing, so this issue had never surfaced. As the amount of embedded generation has increased at certain locations across the network, it has now come to light that the existing formula would double the cost for demand users in a specific zone in 2018/19, reducing in other demand zones to compensate for this increase. In future, as more embedded generation is connected across the network, other zones will also be		We would urge that when National Grid publish their five year forecast of TNUoS tariffs in October 2017 they ensure that all stakeholders are aware of this possible change and reflect them in their tariff publication so suppliers can factor in this risk to their tariffs.	

Response from	Q1: Do you believe that CMP282 Original proposal or either of the potential options for change 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?
	impacted if a solution is not reached. We believe that the original proposal, which is to set any negative demand at a specific node to zero, addresses the defect satisfactorily.			
Andy Colley, SSE	Forecast Demand Tariffs for 2018/19 for Zone 1 have highlighted a manifest error in the weighting applied to locational nodal demand when calculating a price for a Zone - where that Zone contains negative nodal Demand (i.e. exporting GSPs). SSE agree that this is an unintended consequence of the mathematical approach to weighting applied within the Transport and Tariff Model, resulting in an inversion of the intended locational signal for Demand. This outcome, if left unchanged, would artificially increase final Transmission Network Use of System prices to consumers in Zone 1, by inappropriately suppressing the cost-reflective forward looking element of the tariff for Demand. SSE therefore support the proposer's views,	Yes. The error needs to be corrected prior to the publication of final 2018/19 Tariffs in order for Zone 1 consumers to benefit at the earliest opportunity.	No	No

Response from	Q1: Do you believe that CMP282 Original proposal or either of the potential options for change 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?
	as set out in Section 8 of the Workgroup Consultation, that this modification will better facilitate Applicable CUSC Objectives (a) and (b).			
Highlands and Islands Enterprise	Response received in letter form: Underlying locational signals indicate that the Demand Tariff for Demand Zone 1 (North Scotland) should be decreasing but forecasted Demand Tariffs show a disproportionate and significant increase compared to the rest of country. We agree that a modification is required to correct the mistake in the methodology which if left un-corrected will have a negative and unjustified impact on demand customers in North Scotland. It is important that demand tariffs in the north of Scotland remain low to encourage demand in areas of high generation. This has been the economic principle of transmission prices to date. The Highlands and Islands of Scotland have embraced the transition towards a low carbon energy system and demonstrate high levels of embedded generation. The region acts as a sentinel for the wider UK system in that challenges which are experienced here first could realistically impact other parts of the UK in future. It is important therefore to develop a solution that corrects the negative effect on demand in the North of Scotland which can also work for other parts of the UK which are similarly embracing the transition to a low carbon energy system. This sentiment is reflected in the consultation document and it is one that we support. However, while we are pleased that the mistake has been picked up and there is recognition that a solution is required; given that tariff forecasts were published in February 17 it is surprising that it has taken so long to notice and act on. We would therefore expect an explanation to why it was not spotted early and what action National Grid has taken to ensure the appropriate organisations have been informed. Given the February 2017 proposed level of increase for customers in North of Scotland we expect Ofgem and customers groups to be fully informed of subsequent corrections in order that they can also satisfy themselves that charges are representative and customers are not penalised as a consequence of the error.			

Response from	Q1: Do you believe that CMP282 Original proposal or either of the potential options for change 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?
	Rather than developing fixes as an afterthought, we would far rather that zone 1, North of Scotland featured more prominently in the original design of CUSC mods. For the reasons outlined above, we believe that understanding the impacts in zone 1 is tantamount to looking into the future the UK system as a whole and should therefore be a central theme in any consideration of the charging regime to avoid the need for fixes to be developed.			

9 Workgroup Vote

The Workgroup believe that the Terms of Reference have been fulfilled and CMP282 has been fully considered.

The Workgroup met on 6 September 2017 and voted on whether the Original would better facilitate the Applicable CUSC Objectives than the baseline and what option was best overall. Note vote 2 (does the WACM facilitate the objectives better than the Original) was not held due to no WACMs being proposed.

The Workgroup agreed unanimously that the Original was better that the baseline. The voting record is detailed below.

Vote 1: does the original or WACM facilitate the objectives better than the Baseline?

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
Damian Clough – National Grid						
Original	Yes	Yes	Neutral	Neutral	Neutral	Yes
Voting statement: Against A) Consumers in the North of Scotland, if tariffs are passed through by Suppliers will see an unjustified increase in their Electricity bills. If Suppliers choose not to pass this element directly on to the end consumer i.e. (Fixed tariffs) then this will harm competition. Although the defect currently affects consumers in the North of Scotland with the growth of Embedded Generation this could feasibly affect other parts of the country i.e. South West, Wales within 5 years. Against B) Tariffs are meant to provide cost reflective signals. The tariffs currently for North of Scotland clearly do not reflect the underlying cost reflective signals. This may lead to increased Transmission expenditure funded by other users who did not cause this investment						

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
Nicola Fitchett – RWE						
Original	Yes	Yes	Neutral	Neutral	Neutral	Yes
Voting statement: I agree that the current treatment of exporting demand nodes in the tariff model results, under certain circumstances, in users paying demand tariffs which do not reflect the costs imposed on the system by the user. The magnitude of this						

difference means that it should be addressed as soon as possible. The proposed solution produces tariffs which much better reflect the impact of users on the system than the baseline. The solution is simple and easy to implement and will enable the defect to be rectified quickly.

Workgroup Member	**Better facilitates ACO (a)**	**Better facilitates ACO (b)?**	**Better facilitates ACO (c)?**	**Better facilitates ACO (d)?**	**Better facilitates ACO (e)?**	**Overall (Y/N)**
Binoy Dharsi – EDF						
Original	Neutral	Yes	Neutral	Neutral	Yes	Yes
Voting statement: Objective a) Neutral; Objective b) We agree that it results in a most cost reflective methodology; Objective c) Neutral; Objective d) Neutral; Objective e) We agree it meets the requirement in the implementation and administration of the CUSC arrangements by directly and clearly rectifying an obvious defect.						

Workgroup Member	**Better facilitates ACO (a)**	**Better facilitates ACO (b)?**	**Better facilitates ACO (c)?**	**Better facilitates ACO (d)?**	**Better facilitates ACO (e)?**	**Overall (Y/N)**
Daniel Hickman– Npower						
Original	Neutral	Yes	Yes	Neutral	Neutral	Yes
Voting statement: The increasing level of Distributed generation has highlighted an issue with the current methodology whereby the cost reflective price signals created on a nodal basis are diluted /distorted by the zonal averaging procedure. CMP282 takes account of this development by removing the distortion caused by averaging on a zonal basis. Although CMP282 is better than the baseline as it removes the defect and is relatively simple, allowing implementation for 18/19 tariffs, further consideration should be given in the future as to how exporting nodes could be incorporated into the generation methodology rather than simply removed from the demand methodology.						

Workgroup Member	**Better facilitates ACO (a)**	**Better facilitates ACO (b)?**	**Better facilitates ACO (c)?**	**Better facilitates ACO (d)?**	**Better facilitates ACO (e)?**	**Overall (Y/N)**
Robert Longden – Cornwall Energy						
Original	Yes	Yes	Neutral	Neutral	Neutral	Yes
Voting statement: The Modification corrects an unintended error in the operation of the charging methodology. Rectifying this error thus logically better facilitates the charging objectives in the CUSC.						

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
Karl Maryon – Haven Power						
Original	Neutral	Yes	Neutral	Neutral	Neutral	Yes
Voting statement: The Original is the best solution to the defect. It meets CUSC objective (b) in a way that causes minimal overall disturbance to TNUoS demand tariffs.						

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
Simon Lord – Engie						
Original	Yes	Neutral	Neutral	Neutral	Yes	Yes
Voting statement: The proposal details a solution to a defect that was not anticipated when the transport and tariff section of the CUSC was last reviewed. The solution is pragmatic and simple to implement and will ensure that tariffs are more cost reflective than they otherwise would have been.						

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
Andy Colley – SSE						
Original	Yes	Yes	Neutral	Neutral	Neutral	Yes
Voting statement: The proposer has highlighted an unintended consequence of the approach to weighting used within the Transport and Tariff model when calculating locational tariffs for a demand charging zone that contains exporting nodes. If left unchanged, final locational zonal demand tariffs would fail to properly reflect underlying locational signals and distort competition. The solution provides a pragmatic and simple means of addressing the issue, resulting in a more efficient outcome for end consumers impacted by the error that better reflects the costs that they impose on the system. I agree therefore that the CMP282 original proposal better facilitates Applicable CUSC objectives:- a) effective competition - by minimising opportunities to distort competition through pass through of artificial/inappropriate differentials in charges, effective competition and the end consumer is better served; and						

b) Cost reflectivity - by calculating tariffs that are more reflective of the costs imposed upon the system by users in areas with exporting nodes, final tariffs better reflect the costs incurred by the transmission licensees in managing their business. All other objectives are neutral.

Workgroup Member	Better facilitates ACO (a)	Better facilitates ACO (b)?	Better facilitates ACO (c)?	Better facilitates ACO (d)?	Better facilitates ACO (e)?	Overall (Y/N)
James Anderson– Scottish Power						
Original	Yes	Yes	Neutral	Neutral	Neutral	Yes
Voting statement: There is a defect in the current charging methodology which results in inaccurate demand zonal locational signals where there are exporting GSPs (nodes) within a demand TNUoS charging zone. CMP282 addresses this defect by setting all negative demand nodes to zero when calculating he zonal tariff. By addressing the defect, the original proposal provides tariffs which are more reflective of the costs imposed on the system by users on the system when changing demand within a TNUoS charging zone (Applicable Charging Objective (ACO) (b)). By providing a more cost reflective demand charging signal, the original proposal better facilitates competition (ACO (a)). The proposal is neutral against the other ACOs. Overall the proposal better meets the Applicable CUSC Objectives.						

Vote 3: Which option is best?

Workgroup Member	BEST Option?
Damian Clough – National Grid	**Original**
Nicola Fitchett – RWE	**Original**
Binoy Dharsi – EDF	**Original**
Daniel Hickman – npower	**Original**
Robert Longden – Cornwall Energy	**Original**
Karl Maryon – Haven	**Original**
Simon Lord – Engie	**Original**

Andy Colley – SSE	**Original**
James Anderson – Scottish Power	**Original**

10 CMP282: 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 (c) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).	

Charging Objective A

Consumers in the North of Scotland, if tariffs are passed through by Suppliers will see an unjustified increase in their Electricity bills. If Suppliers choose not to pass this element directly on to the end consumer i.e. (Fixed tariffs) then this will harm competition. Although the defect currently affects consumers in the North of Scotland with the growth of Embedded Generation this could feasibly affect other parts of the country i.e. South West, Wales within 5 years.

Charging Objective B

Tariffs are meant to provide cost reflective signals. The tariffs currently for North of Scotland clearly do not reflect the underlying cost reflective signals. This may lead to increased Transmission expenditure funded by other users.

11 Implementation

Proposer’s initial view:

The view of the Proposer was that CMP282 would require minimal system changes as the change would not change any billing systems as demand zones will stay the same. National Grid will need to implement changes to the DCLF model and the code within the model which does require expert Excel knowledge and testing.

12 Legal Text

Below details the proposed changes to Section 14 should CMP282 be approved and implemented.

14.15.40 Generators will have zonal tariffs derived from both, the wider Peak Security nodal marginal km; and the wider Year Round nodal marginal km for the generation node calculated as the increase or decrease in marginal km along all transmission circuits except those classified as local assets.

The zonal Peak Security marginal km for generation is calculated as:

$$WNMkm_{j\,PS} = \frac{NMkm_{j\,PS} * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi\,PS} = \sum_{j \in Gi} WNMkm_{j\,PS}$$

Where

Gi	=	Generation zone
j	=	Node
$NMkm_{PS}$	=	Peak Security Wider nodal marginal km from transport model
$WNMkm_{PS}$	=	Peak Security Weighted nodal marginal km
$ZMkm_{PS}$	=	Peak Security Zonal Marginal km

14.15.41 The zonal Peak Security marginal km for demand zones are calculated as follows. If Nodal Demand from a node is less than 0 (Exporting) the nodal demand will be set to zero and therefore not contribute to the Zonal marginal km~~:~~

$$WNMkm_{j\,PS} = \frac{-1 * NMkm_{j\,PS} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{Di\,PS} = \sum_{j \in Di} WNMkm_{j\,PS}$$

Where:

Di	=	Demand zone
Dem	=	Positive Nodal Demand from transport model

Comment [NG1]: Only Positive Nodal Demand will be calculated

Similarly, the zonal Year Round marginal km for demand zones are calculated as follows:

$$WNMkm_{jYR} = \frac{-1 * NMkm_{jYR} * Dem_j}{\sum_{j \in Di} Dem_j}$$

$$ZMkm_{DiYR} = \sum_{j \in Di} WNMkm_{jYR}$$

14.24 Example: Calculation of Zonal Demand Tariff

Let us consider all nodes in ~~a~~ the same demand zone in this example

The table below shows an ex~~s~~ample output of the transport model comprising the node, the Peak Security and Year Round nodal marginal km of an injection at the node with a consequent withdrawal at the distributed reference node, the generation sited at the node, scaled to ensure total national generation = total national demand and the demand sited at the node.

Where the Demand (MW) is negative this indicates that the Demand node is Exporting rather than i~~I~~mporting.

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)
1	A	110	80	100
1	B	140	90	100
1	C	120	80	0
1	D	100	100	-50
1	E	100	70	50
		Totals		**200**

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)
14	ABHA4A	-77.25	-230.25	127
14	ABHA4B	-77.27	-230.12	127
14	ALVE4A	-82.28	-197.18	100
14	ALVE4B	-82.28	-197.15	100
14	AXMI40_SWEB	-125.58	-176.19	97
14	BRWA2A	-46.55	-182.68	96

14	BRWA2B	-46.55	-181.12	96
14	EXET40	-87.69	-164.42	340
14	HINP20	-46.55	-147.14	0
14	HINP40	-46.55	-147.14	0
14	INDQ40	-102.02	-262.50	444
14	IROA20_SWEB	-109.05	-141.92	462
14	LAND40	-62.54	-246.16	262
14	MELK40_SWEB	18.67	-140.75	83
14	SEAB40	65.33	-140.97	304
14	TAUN4A	-66.65	-149.11	55
14	TAUN4B	-66.66	-149.11	55
		Totals		**2748**

In order to calculate the demand tariff we would carry out the following steps:

(i) Change Negative Demand values to 0 (zero) , which in this example is Node D

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)
1	A	110	80	100
1	B	140	90	100
1	C	120	80	0
1	D	100	100	0
1	E	100	70	50
		Totals		**250**

~~(i)~~(ii) calculate the demand weighted nodal shadow costs

For this example zone this would be as follows:

Demand Zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)	Peak Security Demand Weighted Nodal Marginal km	Year Round Demand Weighted Nodal Marginal km
1	A	110	80	100	44	32
1	B	140	90	100	56	36
1	C	120	80	0	0	0
1	D	100	100	0	0	0
1	E	100	70	50	20	14
		Totals		**250**	**120**	**82**

Demand zone	Node	Peak Security Nodal Marginal km	Year Round Nodal Marginal km	Demand (MW)	Peak Security Demand Weighted Nodal Marginal km	Year Round Demand Weighted Nodal Marginal km
14	ABHA4A	-77.25	-230.25	127	-3.57	-10.64
14	ABHA4B	-77.27	-230.12	127	-3.57	-10.64
14	ALVE4A	-82.28	-197.18	100	-2.99	-7.17
14	ALVE4B	-82.28	-197.15	100	-2.99	-7.17
14	AXMI40_SWEB	-125.58	-176.19	97	-4.43	-6.22
14	BRWA2A	-46.55	-182.68	96	-1.63	-6.38
14	BRWA2B	-46.55	-181.12	96	-1.63	-6.33
14	EXET40	-87.69	-164.42	340	-10.85	-20.34
14	INDQ40	-102.02	-262.50	444	-16.48	-42.41
14	IROA20_SWEB	-109.05	-141.92	462	-18.33	-23.86
14	LAND40	-62.54	-246.16	262	-5.96	-23.47
14	MELK40_SWEB	18.67	-140.75	83	0.56	-4.25
14	SEAB40	65.33	-140.97	304	7.23	-15.59
14	TAUN4A	-66.65	-149.11	55	-1.33	-2.98
14	TAUN4B	-66.66	-149.11	55	-1.33	-2.98
		Totals		**2748**	**-49.19**	**-190.43**

~~(ii)~~(iii) sum the Peak Security and Year Round demand weighted nodal shadow costs to give zonal figures. For this example zone this is shown in the above table and is 120~~49.19~~km for Peak Security background and 82~~190.43~~km for Year Round background.

~~(iii)~~(iv) calculate the transport (locational) tariffs by multiplying the figures in (iii) above by -1. This changes the original Nodal Marginal Km for injecting (Generation) into Nodal Marginal Km for withdrawing (Demand). Then multiply by the expansion constant, the locational security factor and then ~~(&~~ divide~~ing~~ by 1000 to put into units of £/kW~~)~~:

For this example zone, assuming an expansion constant of £10.07/MWkm and a locational security factor of 1.80:

a) Peak Security tariff –

- (120~~49.19~~km * £10.07/MWkm * 1.8) = **-£2~~0~~.47~~89~~/kW**
1000

b) Year Round tariff -

- (8~~0~~2~~190.43~~km * £10.07/MWkm * 1.8) = **-£1.49~~3.45~~/kW**
1000

The Locational signal for Demand within this zone is negative for both Peak and Year Round, which indicates withdrawing at this part of the network, reduces total system flows.

~~(iv)~~(v) We now need to calculate the residual tariff. This is calculated by taking the total revenue to be recovered from demand (calculated as c.73% of total The Company TNUoS target revenue for the year) less the revenue which would be recovered through the demand transport tariffs divided by total expected demand.

Assuming the total revenue to be recovered from TNUoS is £1067m, the total recovery from demand would be (73% x £1067m) = £779m. Assuming the total recovery from demand transport tariffs is £130m and total forecast chargeable demand capacity is 50000MW, the demand residual tariff would be as follows:

$$\frac{\pounds 779m - \pounds 130m}{50000MW} = \underline{\pounds 12.98 / kW}$$

~~(v)~~(vi) to get to the final tariff, we simply add on the demand residual tariff calculated in (v) to the zonal transport tariffs calculated in (iii(a)) and (iii(b))

For zone 1~~14~~:

-£2.47~~0.89~~/kW + -£1.49~~3.45~~/kW + £12.98/kW = **£9~~17~~.32/kW**

To summarise, in order to calculate the demand tariffs, we evaluate a demand weighted zonal marginal km cost, multiply by the expansion constant and locational security factor, then we add a constant (termed the residual cost) to give the overall tariff.

(vii) The final demand tariff is subject to further adjustment to allow for the minimum £0/kW demand charge. The application of a discount for small generators pursuant to Licence Condition C13 will also affect the final demand tariff.

13 Annex 1: CMP282 Terms of Reference

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP282 WORKGROUP

CMP282 seeks to amend how the DCLF model calculates Zonal Locational Demand tariffs so that the final locational zonal demand tariffs accurately reflect the underlying locational signals.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP282 'The effect Negative Demand has on Zonal Locational Demand Tariffs'** raised by **National Grid** at the Modifications Panel meeting on 30 June 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) Consider the practical implications of solution e.g. that data is available to National Grid to support the proposed solution and any system changes
   b) Consider the impact on the locational signals
   c) Consider the interaction with other open Modifications

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

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

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

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

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

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

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

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **21 September 2017** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **29 September 2017**.

Membership

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

Role	Name	Representing
Chairman	Caroline Wright	Code Administrator
Technical Secretary	Heena Chauhan	Code Administrator
National Grid Representative/Proposer	Damian Clough	National Grid
Industry Representatives	Binoy Dharsi Charlie Friel Dan Hickman James Anderson Karl Maryon Nicola Fitchett Simon Lord Robert Longden Andy Colley	EDF Ofgem npower Scottish Power Haven Power RWE Engie (First Hydro nominated) Cornwall Energy (Fred Olsen nominated) SSE
Authority Representatives	Charlie Friel	OFGEM

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 CMP282 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

Proposed CMP282 Timetable

22 Jun 2017	CUSC Modification Proposal submitted
30 Jun 2017	CUSC Modification tabled at Panel meeting
22 Jul 2017	Request for Workgroup members (5 Working days)
14 Jul 2017	Workgroup meeting 1
18 Jul 2017	Workgroup meeting 2
21 Jul 2017	Workgroup meeting 3
24 Jul 2017	Workgroup Consultation issued (10 Working Days)
4 Aug 2017	Deadline for responses
w/c 14 Aug 2017	Workgroup meeting 4 **(WG review Consultation Reponses)**
w/c 28 Aug 2017	Workgroup meeting 5 (WG to agree options for WACMs)
21 Sep 2017	Workgroup report issued to CUSC Panel
29 Sep 2017	CUSC Panel meeting to discuss Workgroup Report

2 Oct 2017	Code Administrator Consultation issued (10 Working days)
13 Oct 2017	Deadline for responses
18 Oct 2017	Draft FMR published for industry comment (3 Working days)
23 Oct 2017	Deadline for comments
19 Oct 2017	Draft FMR circulated to Panel
27 Oct 2017	CUSC Panel Recommendation vote
27 Oct 2017	FMR circulated for Panel comment (3 Working days)
1 Nov 2017	Deadline for Panel comment
3 Nov 2017	Final report sent to Authority for decision
1 Dec 2017	Implementation date

14 Annex 2: Ofgem's Urgency CMP282 decision letter

Making a positive difference
for energy consumers

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

Direct Dial: 020 7901 9951
Email: sean.hennity@ofgem.gov.uk

Date: 25 July 2017

Dear Mr Toms,

CUSC Modifications Panel views on Urgency for CMP282 'The effect negative demand has on zonal locational demand tariffs'

On 22 June 2017, National Grid (the Proposer) raised CMP282, with a request that it should be treated as an urgent CUSC Modification Proposal. CMP282 aims to amend how the 'DC Load Flow' (DCLF) model calculates Zonal Locational Demand tariffs so that the final locational zonal demand tariffs more accurately reflect the underlying locational signals.

On 3 July, the CUSC Modification Panel (the Panel) wrote to us requesting our decision on whether to grant urgency to CMP282. The Panel's view was that urgency should be granted for CMP282, this decision was supported by the majority of the Panel.

This letter confirms that we consider that modification proposal CMP282 should not be progressed on an urgent basis but on an accelerated timetable.

Background to the proposal

In February 2017, National Grid published forecast Transmission Network Use of System tariffs for charging years 2018/19 to 2021/22.[1] The document includes forecasts of half-hourly and non-half hourly demand tariffs for each transmission system demand zone. Beginning in charging year 2018/19, forecasts showed a significant increase in forecast tariffs in the North Scotland zone. Upon further investigation, the Proposer considers this increase was attributable to an unintended consequence of the model used to calculate demand locational tariffs rather than reflective of actual costs on the system.

The proposal

The Proposer considers that the current model for calculating the Zonal Locational Demand tariffs contains a defect. The Proposer considers that a defect with the model arises where demand at specific locations ('nodes') within a zone becomes negative. In these cases, the proposal states that negative demand has the effect of increasing the locational demand tariff when the underlying locational signals show that it should decrease it.

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

CMP282 aims to amend this defect so that the final zonal demand tariffs more accurately reflect the underlying locational signals. The Proposer does not consider the issue relates to the underlying locational signals themselves.

The Proposer notes that beginning in charging year 2018/19, the number of demand nodes forecast to export at Peak (ie have negative demand) is expected to increase to such an extent that they forecast the defect will have a material impact on demand tariffs. They consider that if the defect is not resolved, future demand tariffs will not accurately reflect the costs imposed on the system.

The Proposer considers that the identified defect could be addressed under a standard timetable, but has requested urgency to meet the Draft publication of TNUoS tariffs, expected in December 2017. Final tariffs are due to be published at the end of January 2018.

Panel Discussion

The Panel considered CMP282 and the associated request for urgency at its meeting held on 30 June 2017. The Panel wrote to us on 3 July with its recommendation on the urgency request made by the Proposer.

The majority view of the Panel was that CMP282 should be treated as urgent. However, the Panel expressed the view that there is likely to be more than one solution to the identified defect. The Panel set out, in an Appendix to its letter, both a proposed urgent and standard workgroup timetable for development of CMP282.

Our Views

In reaching our decision, we have considered the details contained within the proposal, the Proposer's justification for urgency and the views of the Panel. We have assessed the request against the criteria set out in Ofgem's published guidance,[2] in particular whether it is linked to "*an imminent issue or a current issue that if not urgently addressed may cause a significant commercial impact on parties, consumers or other stakeholder(s)".*

It is our view that both the urgent and standard timetables provided to the Authority would enable the modification to be implemented, if approved, ahead of final tariff setting in January 2018. As such, we do not consider a case has been made that the modification needs to be treated urgently to address the identified defect (if appropriate), or that it will therefore have a significant commercial impact on parties, consumers or other stakeholders.

For the avoidance of doubt, in not granting this request for urgency, we have made no assessment on the merits of the proposal and nothing in this letter in any way fetters the discretion of the Authority in respect of this proposal.

Yours sincerely,

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

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[2] The guidance document is available here: https://www.ofgem.gov.uk/publications-and-updates/ofgem-guidance-code-modification-urgency-criteria-0

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

15 Annex 3: CMP282 Attendance Register

A – Attended

X – Absent

O – Alternate

D – Dial-in

Name	Organisation	Role	14 July 2017	21 July 2017	16 August 2017	6 September 2017
Caroline Wright	National Grid	Chair	A/D	A/D	A/D	A/D
Heena Chauhan	National Grid	Technical Secretary	X	X	X	A/D
Damian Clough	National Grid	Proposer/NG Representative	A/D	A/D	A/D	A/D
Nicola Fitchett	RWE	Workgroup Member	X	A/D	A/D	A/D
Bill Reed	RWE	Workgroup Alternate	A/D	X	X	X
Binoy Dharsi	EDF	Workgroup Member	A/D	A/D	A/D	A/D
Dan Hickman	Npower	Workgroup Member	A/D	A/D	A/D	A/D

Simon Lord	Engie (nominated by First Hydro Company)	Workgroup Member	A/D	A/D	A/D	A/D
James Anderson	Scottish Power	Workgroup Member	X	X	A/D	A/D
Robert Longden	Cornwall Energy (nominated by Fred Olsen Renewables)	Workgroup Member	A/D	A/D	A/D	A/D
Karl Maryon	Haven Power	Workgroup Member	X	A/D	X	A/D
Claire Warren	Haven Power	Workgroup Alternate	X	X	A/D	X
Andy Colley	SSE	Workgroup Member	A/D	A/D	A/D	A/D
Charlie Friel	Ofgem	Workgroup Observer	A/D	A/D	X	A/D
Sean Hennity	Ofgem	Workgroup Observer	X	X	A/D	X

