nationalgrid

Stage 02: Workgroup Consultations

Connection and Use of System Code (CUSC)

CMP264: Embedded Generation Triad Avoidance Standstill and **CMP265:** Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market

What stage is this document at?

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

CMP264 aims to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those New Embedded Generators who export on to the system, when determining liability for locational and wider HH demand TNUoS charges.

CMP265 aims to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those embedded generators who are in the Capacity Market who export on to the system, when determining liability for the residual HH demand TNUoS charges.

This document contains the discussion of the Workgroups for CMP264 and CMP265 which formed in June 2016 to develop and assess the two proposals. Any interested party is able to make a response in line with the guidance set out in Section 6 of this document.

Published on:	**2 August 2016**
Length of Consultation:	**16 Working days**
Responses by:	**24 August 2016**

The Workgroup concludes:
To be completed following the Workgroup Consultation

High Impact:
Suppliers and embedded generators

Contents

Any Questions?

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About this document

This document is a Workgroup consultation which seeks the views of CUSC and interested parties in relation to the issues raised by the Original CMP264 CUSC Modification Proposal and the Original CMP265 CUSC Modification Proposal developed by the Workgroups. Parties are requested to respond by **5pm** on **24 August 2016** to CUSC.team@nationalgrid.com using the Workgroup Consultation Response Proforma which can be found on the following links:

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/

Document Control

Version	Date	Author	Change Reference
1.0	2 August 2016	Code Administrator	Workgroup Consultation to Industry

1 Summary

1.1 Purpose of Document

1.1.1 This document describes the Original CMP264 CUSC Modification Proposal (the CMP264 Proposal) and the Original CMP265 CUSC Modification Proposal (the CMP265 Proposal). For both Proposals it summarises the deliberations of the Workgroup and sets out the options for potential Workgroup Alternative CUSC Modifications (WACMs). Prior to confirming any alternative proposals the Workgroup are seeking views on the options they have identified, what is the best solution to the possible defect set out in both proposals and also any other further options that respondents may propose.

1.2 Structure of this report

1.2.1 This document is a Workgroup consultation which seeks the views of CUSC and interested parties in relation to the issues raised by the Original CMP264 CUSC Modification Proposal which was raised by Scottish Power and developed by the Workgroup, and the Original CMP265 CUSC Modification Proposal which was raised by EDF Energy and developed by the Workgroup.

1.2.2 Due to the commonality between the workgroup discussions, the similarity in topics and for ease of use the Workgroup has prepared a single Workgroup Consultation document. Conscious however that the modification are being treated separately by the CUSC Panel, there are two separate consultation to which responses are invited from industry parties to one or both consultations.

1.2.3 Parties are requested to respond by **5pm on 24 August 2016** to CUSC.team@nationalgrid.com using the Workgroup Consultation Response Proforma which can be found on the following links:

(a) http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

(b) http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/

1.2.4 Within this document, different formatting is used to distinguish between section applicable to both modifications, or to only one of the modifications:

(a) sections which applicable to both modifications are left in normal black type.

(b) sections which apply only to CMP264 are marked with a GREEN border

(c) sections which apply only to CMP265 are marked with a RED border

1.3 CMP264: Generation Triad Avoidance Standstill

1.3.1 CMP264 was proposed by Scottish Power and was submitted to the CUSC Modifications Panel for its consideration in May 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the relevant CUSC Applicable Objectives. The Workgroup is required to consult on the Proposal during this period to gain views from the wider industry (this Workgroup Consultation). Following this Consultation, the Workgroup will consider any responses, vote on the best solution to the proposed defect, and report back to the Panel at the September 2016 Panel meeting[1].

1.3.2 CMP264 aims to change the Transport and Tariff Model and billing arrangements to remove the netting[2] of output from those New Embedded Generators who export on to the system, when determining liability for locational and wider HH demand TNUoS charges. The proposal is to apply until such as time as Ofgem has completed its consideration of the current electricity Transmission Charging Arrangements[3] (and any review which ensues) and any resulting changes have been fully implemented.

1.3.3 The Workgroup is currently considering whether the locational element of the demand TNUoS tariff, could be retained as an embedded benefit for New Embedded Generators. Consultation Question 17 seeks industry views on this topic.

1.3.4 This Workgroup Consultation has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid Website, http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/ along with the Modification Proposal Form.

1.4 CMP265: Gross charging of TNUoS for HH demand where Embedded Generation is in the Capacity Market

1.4.1 CMP265 was proposed by EDF Energy and was submitted to the CUSC Modifications Panel for its consideration in May 2016. A copy of this Proposal is provided within Annex 1. The Panel decided to send the Proposal to a Workgroup to be developed and assessed against the relevant CUSC Applicable Objectives. The Workgroup is required to consult on the Proposal during this period to gain views from the wider industry (this Workgroup Consultation).Following this Consultation, the Workgroup will consider any responses, vote on the best solution to the proposed defect and report back to the Panel at the September 2016 Panel meeting[4].

1.4.2 CMP265 aims to change the Transport and Tariff Model and billing arrangements to remove the netting of output from those embedded generators who are in the Capacity Market and export on to the distribution network, when determining liability for the residual HH demand TNUoS charges.

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1 The CUSC Panel agreed at its September 2016 meeting to accept an extension to the CMP265 Workgroup to allow the workgroup to report to the September Panel meeting. It had originally been scheduled to report to the August Panel meeting.

2 Net and Gross charging are discussed later in the document, starting in paragraph 2.3.7.

3 See Section 2.17 of Ofgem's Forward Work Plan 2016/17 https://www.ofgem.gov.uk/publications-and-updates/forward-work-programme-2016-17

4 The CUSC Panel agreed at its September 2016 meeting to accept an extension to the CMP265 Workgroup to allow the workgroup to report to the September Panel meeting. It had originally been scheduled to report to the August Panel meeting.

1.4.3 This Workgroup Consultation has been prepared in accordance with the terms of the CUSC. An electronic copy can be found on the National Grid Website, http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/ along with the Modification Proposal Form.

2 Summary of Proposals and Background Information

2.1 Summary of the process to date

2.1.1 For both Workgroups, each Workgroup has met five times to discuss and clarify the defect and the proposed rectification approach. The first meeting were held as separate meetings on consecutive days; for subsequent meetings the material and meetings have been held as joint CMP264/CMP265 Workgroup meetings.

2.1.2 The CUSC Panel was asked at its meeting on 29 July 2016, to accept an extension to the CMP264 and CMP265 Workgroup to allow the workgroup to report to the September Panel meeting, given the breadth of discussion held on the issues. Both modifications had originally been scheduled to report to the August Panel meeting.

2.2 Original Proposals and Defect

CMP264: Statement of the Original Proposal and Defect

2.2.2 At the first workgroup meeting, the Proposer – Scottish Power – ran through its modification proposal, including the defect and the Original proposal. The full detail of the defect as specified by the proposer is detailed in Annex 1 of this document in the modification proposal form.

CMP265: Statement of the Original Proposal and Defect

2.2.3 At the first workgroup meeting, the Proposer – EDF Energy – ran through its modification proposal, including the defect and the Original proposal. The full detail of the defect as specified by the proposer is detailed in Annex 3 of this document in the modification proposal form.

Comparison of the Original CMP264 and Original CMP265 Proposals

2.2.4 A summary of the two Original proposals is shown in Table 1. Specific alternative proposals to each Original are covered in Section 4.

	CMP264 Original Proposal	CMP265 Original Proposal
Proposer	Scottish Power	EDF Energy
Proposal	Do not deduct new Embedded Generation from a suppliers' charging volumes, for the purposes of demand TNUoS. Thereby, removing demand TNUoS embedded benefit for those new embedded generators.	Do not deduct certain embedded generation (those with Capacity Market agreements) from a suppliers' charging volumes, for the purposes of demand TNUoS. Thereby, removing demand TNUoS embedded benefit for those embedded generators.
Affected Embedded Generators who have a different value of the embedded benefit under the proposal	Embedded generators defined as "New" after 30 June 2017	All Embedded Generators with a capacity market agreement.
Demand TNUoS Embedded benefit for the affected generators[5]	New Embedded Generators will receive no demand TNUoS embedded benefit (neither the locational nor the residual) The workgroup would be interested in views on whether the Locational tariff should be retained (see consultation question 17)	Affected Embedded Generators would receive the locational demand TNUoS tariffs as an embedded benefit, but not the demand residual.
Implementation Date (for changes to charging methodology)	1 April 2017 The first affected volumes would be for "new embedded generators" during the 2017/18 November – February Triad season.	1 April 2020
Disapplication	Intended as a 'stop-gap' solution until Ofgem confirms that it has completed its consideration of the issues (and any review which may ensue) and any resulting changes have been fully implemented.	No. Enduring solution, unless superseded by an implemented outcome of Ofgem/Grid wider review of charging arrangements that has effect in the same area of the CUSC.
Related BSC Modification	P349 – Facilitating embedded generation Triad Avoidance Standstill	P348 - Provision of gross BM Unit data for TNUoS charging

Table 1: Comparison of the Original CMP264 and CMP265 proposals

5 For SVA registered embedded generators (the majority) the embedded benefit is paid through the supplier, so any changes affect supplier TNUoS charges and so the embedded generator indirectly. For CVA registered embedded generators the demand TNUoS embedded benefit is received directly from National Grid.

2.3 Background Information

2.3.1 The workgroup held a number of discussions on topics relating to the two modifications. This section summarises the background discussion on the following topics:

(a) Definitions of embedded benefits and what is being considered by these modifications

(b) How does demand TNUoS work, and net Charging

(c) Current signals for embedded generation from TNUoS

(d) Definitions of embedded benefits and what is being considered by these modifications

(e) Reducing demand TNUoS charge liability

(f) Future and Historic Value of the Demand Residual

(g) How the demand TNUoS embedded benefit is funded by suppliers

(h) Access to Market for embedded generators

(i) Previous reviews in this areas

Definitions of embedded benefits and what is being considered by these modifications

2.3.2 Embedded benefits, in general, refer to charges avoided or paid to generation which is connected to the distribution network (rather than the transmission network) and is licence exempt[6]. In England and Wales, the distribution network is for generators connected at 132kV or lower; In Scotland it applies at 66kV or lower, by virtue of 132kV being defined as transmission voltage in Scotland.

2.3.3 Generation in Scotland, connected at 132kV, receives the ‘small generator discount’ in addition to its TNUoS charge to account, in part, of the difference in treatment of 132kV generation across the county. This discount was extended until March 2019, and is currently valued at £11.45/kW (one quarter of the sum of the generation and demand residual).

2.3.4 Embedded benefits typically refer to a number of key areas of charges which an embedded generator may benefit from depending on their operations and commercial arrangements. The ELEXON guidance document[7] lists four main types of embedded benefits:

(a) **Generation TNUoS**. Embedded generators that do not have a Bilateral Embedded Generation Agreement with National Grid (BEGA)[8] do not pay TNUoS generation charges. .

6 For more information on licence exemption, see https://www.gov.uk/guidance/electricity-licence-exemptions

In general, generators with a capacity of less than 100MW, connected to the distribution network, are exemptible.

7 https://www.elexon.co.uk/wp-content/uploads/2016/01/Embedded_Generation_v7.0.pdf

8 CUSC Section 14.18 Generation charges - Parties Liable for Generation Charges 14.18.1 “The following CUSC parties shall be liable for generation charges: i) Parties of Generators that have a Bilateral Connection Agreement with The Company. ii) Parties of Licensable Generation that have a Bilateral Embedded Generation Agreement with The Company”.

(b) **Demand TNUoS.** . Embedded generators cause a reduction in the net demand (see paragraph 2.3.7) of suppliers during the three hourly peak demand settlement periods as defined under the charging methodology known as the Triad periods. TNUoS tariffs for the Triad period are set on the forecast position of suppliers net of embedded generation output. If the embedded generation forms part of a supplier's half hourly charging base and outputs at the time of Triad this reduces the supplier's liability for TNUoS; based on the contractual relationship between the supplier and the embedded generator some or all of this benefit will be passed on to the embedded generator. Certain CVA[9] registered embedded generators can receive a Triad benefit directly from National Grid,

(c) **BSUoS.** Embedded generators do not pay BSUoS directly. Supplier BSUoS is charged on a net basis, therefore, the output of the embedded generator will be included in the Supplier volume as a negative demand thus reducing the overall value of the demand and consequently the amount of BSUoS charges for which the Supplier is liable.

(d) **Transmission Losses.** An embedded benefit can be realised due to netting off of Supplier's demand due to the output from embedded generation; as only the net value is used to calculate transmission losses an embedded benefit is realised.[10].

2.3.5 Other potential embedded benefits were discussed by the workgroup, although there was no consensus on what is considered an embedded benefit. In particular the *avoidance of CM Supplier Levy* was discussed; as this is charged on a net basis, an embedded generator reduces its supplier's liability for the charge. It was further noted that DBEIS[11] are proposing a consultation on whether the charging base for the Capacity Market Supplier Levy should be changed to avoid the ability of an embedded generator being able to reduce a Supplier's obligations.

2.3.6 For the purposes of these two modifications, it is only the demand TNUoS Embedded Benefit (b above) that is under consideration. This is sometimes referred to as TRIAD avoidance (see below).

How does demand TNUoS apply, and net charging

2.3.7 The embedded benefit under consideration for both of these modifications is the demand TNUoS embedded benefit. In this context, the workgroup have explored how this is currently calculated and charged to suppliers.

2.3.8 Further details on broader TNUoS tariffs can be found in tutorial material provided by National Grid[12] and a short summary is included in Annex 7 Section 7.4.

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[9] CVA – Central Volume Allocation

[10] The Competition and Markets Authority, under their Energy Market Investigation (https://www.gov.uk/cma-cases/energy-market-investigation), has concluded that the absence of locational pricing for transmission losses has an adverse effect on competition. Therefore, in line with the CMA's determination, National Grid have raised BSC Modification P350 to introduce a Transmission Loss Factor for each Grid Supply Point (GSP) Group for each BSC Season in order to allocate transmission losses on a geographical basis.

[11] Department for Business, Energy and Industry Strategy – the successor department to the Department of Energy and Climate Change

[12] http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Tools-and-Data/

2.3.9 Demand TNUoS is charged by National Grid to Suppliers to recover the majority of the allowed revenue for the onshore TOs, OFTOs and other funds such as the Network Innovation Fund. In 2016/17 £2.2bn, of a total of £2.7bn, is recovered from suppliers. The remainder is recovered from transmission connected generators[13].

2.3.10 TNUoS tariffs are set *ex ante*, 2 months ahead of the start of the charging year, to recover the allowed revenue. The tariffs are based on forecasts of the system for the year ahead. Any over or under-recovery of revenue in a given year's results is carried forward to 2 years later, when it is added to the allowed revenue. The allowed revenue is set under the RIIO price control period, or under the OFTO licences.

2.3.11 National Grid sets tariffs and recovers demand TNUoS on the basis of **net demand**. That is the demand that it sees at the Grid Supply Point Group – the offtake from the Transmission Network to the Distribution Networks typically recorded in MWh per settlement period[14]. Net demand is the demand used by each of the customers from the distribution network (known as gross demand) less any energy produced from generators embedded on the distribution network, as summarised in Figure 1. It should be noted that embedded generation that is used to meet onsite localised demand (e.g. Demand Side Response via standby diesel/gas generation) reduces gross demand and is therefore not visible – this is known as "behind the meter" generation and is not affected by this modification.

2.3.12 For TNUoS charging purposes the energy MWh per settlement period is converted into a capacity MW figure. TNUoS HH Demand Tariffs are charged on a £/kW basis.

Figure 1: How net demand at a GSP is structured

2.3.13 In order to set tariffs National Grid forecasts the 'net demand' is forecast on the basis of supplier forecasts and models. Throughout the year, actual data is received by National Grid from ELEXON in a P0210 file 'TUOS Report' file for SVA metered volumes and in a SAA-I014 file for the CVA metered volumes as BMU metered data. National Grid is not currently provided with the figures for gross demand, or the figure of energy from embedded generation.

13 Distribution connected generators who are not licence exempt also pay for generation TNUoS, and do not receive embedded benefits. Typically, this is for embedded generators which are greater than 100MW capacity.

14 Metered data is adjusted to take account of losses incurred over the Distribution System to the Transmission System.

2.3.14 As a simplified illustrative example of how the tariffs are set, consider Table 2. In this example the tariff is set[15] as £2,200m / 48 GW – the amount of revenue to be recovered divided by the forecast charging base. This gives a tariff of £45.83/kW for half-hourly metered demand[16]. This tariff is charged to suppliers on the basis of its average demand over the Triad periods; Triads are the three half-hour periods of highest system net demand during the period November to February, separated by a minimum of 10 days.

2.3.15 In the following illustrative example, we assume that all demand is charges as HH. In reality, HH tariffs are set and charged to HH demand customers, and the remaining two-thirds charged to non-half-hourly customers based on profile data of their usage between 4pm and 7pm over the whole year. The workgroup have not undertaken any detailed analysis on the impact on NHH tariffs, but refer to 2.3.32 for further discussion.

2.3.16 Let us suppose we have four suppliers, A through D. They all forecast net demand to be 12GW each - to give a system total of 48GW which was used about to set the tariff. It is also noted that supplier A has no embedded generation, and Suppliers B, C and D all reduce their net demand compared to their gross demand due to embedded generation.

2.3.17 In the outturn, all Suppliers all use the same net demand as their forecast; however, Supplier B has an additional 1GW of gross demand, but it is offset by an increase of 1GW of embedded generation meaning the net demand as seen by National Grid is unchanged. Therefore, as net demand is unchanged and matches the forecast the total amount of money recover from TNUoS from supplier is equal to the allowed revenue.

		SYSTEM	Suppliers			
			A	B	C	D
Total allowed revenue	**£m**	2200				
Forecast net demand	**GW**	**48**	**12**	**12**	**12**	**12**
Gross demand	*GW*		*12*	*13*	*14*	*16.5*
Embedded generation	*GW*		*0*	*-1*	*-2*	*-4.5*
Tariff	£/kW	45.83				
Actual net demand	**GW**	**48**	**12**	**12**	**12**	**12**
Gross demand	*GW*		*12*	*14 (+1)*	*14*	*16.5*
Embedded generation	*GW*		*0*	*-2 (-1)*	*-2*	*-4.5*
Supplier TNUoS Bill	**£m**	**2200**	550	550	550	550

Table 2: Tariffs with baseline net demand

2.3.18 Net demand is the current basis for setting and billing demand TNUoS tariffs, and therefore, embedded generation and demand reduction enable suppliers to reduce their liability for demand TNUoS by offsetting their gross demand with embedded generation and demand reduction.

15 In the actual charging methodology there is also a locational component (discussed below) calculated on a zonal basis. This example is akin to have a zero locational charge and calculating the residual

16 In the actual charging methodology some of this is pro-rated to non-half-hourly metered customers through a p/kWh tariff applied between 4pm and 7pm each day.

2.3.19 As the total value of TNUoS is fixed (under the price control), using the net demand charging base rather than gross demand, result in TNUoS tariff unit rate which are higher. By netting off embedded generation from gross demand allows a supplier to reduce their liability; as the total amount of TNUoS is fixed, another supplier has to have an increased charge.

Current signals for embedded generation from TNUoS

2.3.20 For 2016/17, the total amount of money to be recovered is £2.7bn. This is recovered by National Grid System Operator, on behalf of the Transmission Owner as defined in Section 14 of the CUSC. The total revenue to be recovered through TNUoS through until 2020/21 is shown in Figure 2 for each of the TOs.

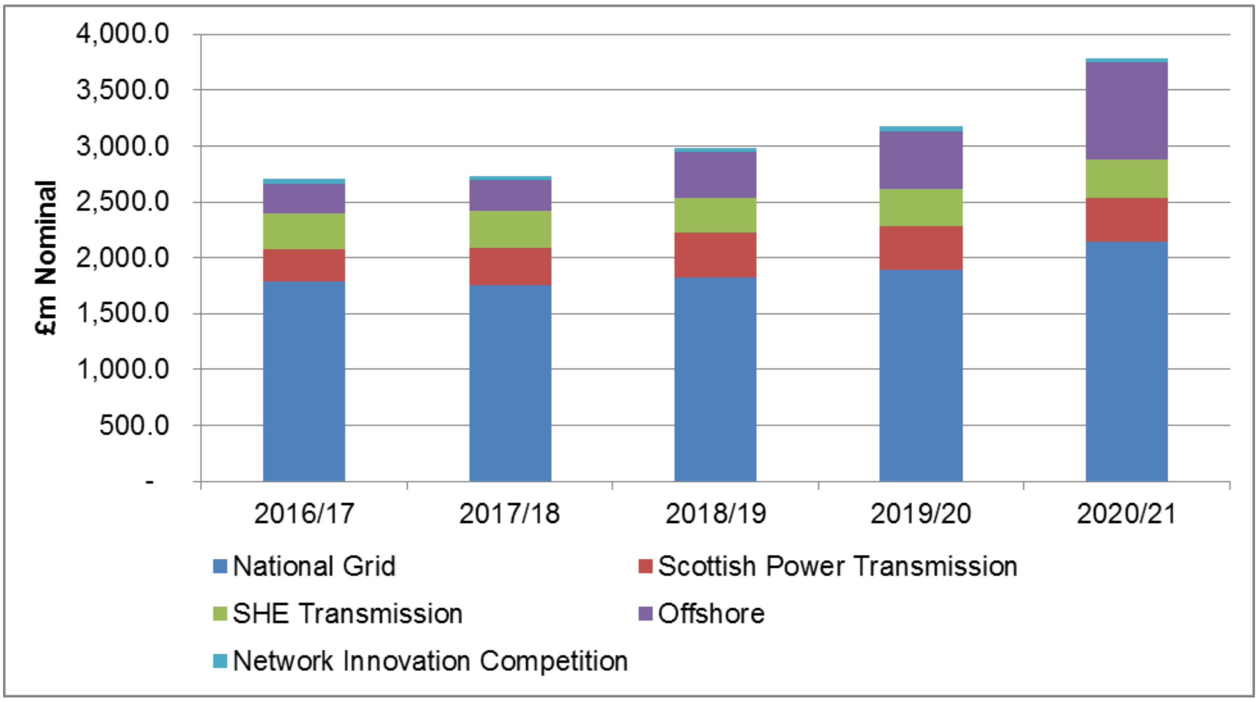


Figure 2: Total value of TNUoS, by source, until 2020/21 from the National Grid five-year forecast[17] (February 2016)

2.3.21 The allowed revenue is determined on the basis of the RIIO price control (and OFTO licences). In the longer term the allowed revenue will depend on agreement at the price control based on the future expected replacement and development of the transmission network, which is dependent on the location and size of future transmission and embedded generation, and demand.

2.3.22 NGET presented an explanation of where TNUoS is recovered from and the Workgroup discussed the different drivers behind the historic and future forecast of the Demand Residual tariff. The drivers discussed included the annual recovery value from Offshore Local Circuits, Onshore Local Circuits, Onshore Substations, the impact of the €2.50/MWh cap, the value of the Generation Residual, self-reinforcing impacts of more embedded generation connecting each year and the trends in the overall TNUoS revenue allowance.

17 http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=45336

2.3.23 The workgroup explored the RIIO-T1 allowed revenues in further detail, as summarised in Annex 7.5. The conclusions were as follows:

(a) Locational charges are for things that are locationally demonstrable – such as a local substation charge, and charges for flows on a local circuit and the wider zonal tariff based on the ICRP load flow methodology. Everything else is just a charge applied via the residual.

(b) The residual component of the demand tariff is used to ensure that NG/TOs recover their allowed revenue.

(c) From the perspective of the transmission network, a unit of distributed generation is a form of negative demand and has the same impact on transmission network as a unit of reduced demand at the same Grid Supply Point.

(d) In the short term the costs of the network do not change significantly regardless of particular development in generation at either transmission or embedded.

(e) System peak is lower today due to a number of factors, including embedded generation, and therefore some argued that embedded generation has resulted in a smaller transmission network and hence lower cost than otherwise may have been (see Figure 3 for historic net demand peaks). Others pointed out that additional embedded generation in constrained areas of the system, for example Scotland, has contributed to a need for more transmission circuits to be constructed, to allow their power to be exported from these areas.

(f) The network and today's allowed revenues are on the basis of the historic decisions made about the location of generation and demand and the associated network.

(g) Workgroup members noted with concern the additional cost to end consumers, due to the significantly faster-than-inflation rising cost of total TNUoS over the next 5 years. Total TNUoS is forecast to increase on average by 8.8% per annum, and one component OFTO revenue by 35.3% per annum. It was noted that the allowed revenue of the TOs are agreed by Ofgem. A large growth in future TNUoS is due to the growth in offshore networks and the revenues of OFTOs.

2.3.24 Overall generation TNUoS charged to transmission connected generation and licenced embedded plant must comply with Regulation (EU) No. 838/2010[18], and specifically a €2.50/MWh cap on average tariffs. Through the interpretation in the CUSC this sets a total cap on the amount of revenue that can be recovered from generation by converting euros to pounds, and using a forecast of volume of energy produced by transmission generation. In the tariffs, the generation residual is used to ensure the total to be recovered from generation does not exceed the cap; therefore from 2016/17 the generation residual is forecast to be negative, as the sum of monies recovered from the locational, local circuits, offshore circuits, local substations is greater than that allowed under the Cap, as shown in Table 3.

2.3.25 Following the UK's referendum result to leave the European Union, it is worth noting that until such a point as a decision is made about the impact of European legislation, Regulation (EU) No 838/2010 and others continue to apply in the UK, therefore, in accordance with the CUSC TNUoS tariffs will continue to be set in accordance with the €2.50/MWh cap. If the cap were to be removed, as part of the UK's negotiation or otherwise, CMP255 which is currently with the Authority has considered what would happen to the G/D split with the defect in CMP255 being stated as a potential "snap-back" to the historic split with generation paying 27% of TNUoS.

[18] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:250:0005:0011:EN:PDF

2.3.26 The allowed revenue not recovered from the generators is recovered from the demand tariffs. The demand tariffs include a zonal location tariff set on the basis of each DNO area, which recovers in total -£2.4m in 2016/17. The remainder must be collected through the residual, which is a flat uniform charge applied to all demand customers. Although the term *residual* is often taken to imply a small amount in common English, under the 2016/17 charges it recovered over £2.2bn, or over 80%, of the total TNUoS revenue. Given the cap on the generation tariffs, this value of demand residual is expected to increase in future.

2.3.27 The future components of the TNUoS are shown in Table 3. The value of demand TNUoS embedded benefit is taken from Table 5 for comparison.

£m	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Generation TNUoS					
Locational Generation	191.9	266.3	305.1	325.9	329.0
Offshore Local Circuits	200.6	212.9	309.2	402.9	673.7
Onshore Local Circuits	13.3	15.6	27.6	23.0	21.2
Onshore Substation	15.9	17.0	23.6	26.0	28.1
Generation Residual	31.8	-61.9	-233.3	-370.3	-671.4
TOTAL	**453.4**	**449.9**	**432.3**	**407.5**	**380.6**
Demand TNUoS					
Locational Demand	-2.4	0.6	-0.9	-0.1	2.0
Demand Residual	2257.6	2284.6	2551.7	2767.3	3406.9
Total Demand	**2255.2**	**2285.2**	**2550.8**	**2767.2**	**3408.9**
Total TNUoS	**2708.7**	**2735.0**	**2983.1**	**3174.7**	**3789.5**
Estimated value of embedded benefit taken from Table 5[19] for comparison[20]					
National Grid Analysis from FES	343.4	374.2	465.2	526.3	649.7
KMPG report for UK Power Reserve	272				
G/D Split (due to €2.50/MWh cap)					
Generation %	16.7%	16.4%	14.5%	12.8%	10.0%
Demand %	83.3%	83.6%	85.5%	87.2%	90.0%

Table 3: Summary of components of the TNUoS tariffs from five-year forecast

2.3.28 The current forecast demand TNUoS tariffs for HH demand for 2017/18, as published by National Grid in June 2016[21] are shown in Table 4. The small generator discount is applied to all demand tariffs (and generation tariff) on a flat rate to provide the support for 132kV transmission connected generator primarily in Scotland.

19 Value of Embedded Benefit based on the product of forecast increase in embedded MW and the annual forecast Demand TNUoS Tariff

20 In addition, the 'Cornwall Energy Review of Embedded Generation Benefits Report for the Association for Decentralised Energy' placed a total value for 2015/16 of £293m for embedded benefit

21 http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=8589935681

Zone	Zone Name	HH Demand Tariff (£/kW)			
		Locational	Small Generator Discount	Residual	TOTAL
1	Northern Scotland	-17.62	0.62	47.95	30.95
2	Southern Scotland	-17.69	0.62	47.95	30.88
3	Northern	-9.17	0.62	47.95	39.40
4	North West	-3.10	0.62	47.95	45.47
5	Yorkshire	-3.24	0.62	47.95	45.33
6	N Wales & Mersey	-1.37	0.62	47.95	47.20
7	East Midlands	0.00	0.62	47.95	48.58
8	Midlands	1.46	0.62	47.95	50.04
9	Eastern	1.93	0.62	47.95	50.50
10	South Wales	-1.41	0.62	47.95	47.17
11	South East	4.90	0.62	47.95	53.47
12	London	7.38	0.62	47.95	55.95
13	Southern	5.88	0.62	47.95	54.45
14	South Western	4.47	0.62	47.95	53.05

Table 4: 2017/18 Demand TNUoS tariffs showing the breakdown of locational and residual

2.3.29 The locational signal reflects the marginal cost of taking additional demand within that zone. For example, Scotland (zones 1 and 2) taking demand is incentivised by a locational tariff; similarly an embedded generator exposed only to the locational tariff would be charged if exporting as negative demand over the Triad. However, on balance, the locational charge does not fully offset the residual benefit (£47.95/kW), so an embedded generator in Scotland is able to make an income of around £31/kW for output at Triad.

2.3.30 The incentive to reduce demand or produce generation is the same £/kW. The Triad avoidance value received by both distributed generators or distributed demand users may indicate either that the residual Triad benefit is too high, or that the regional allocation of the Triad charge is not cost reflective.

Reducing demand TNUoS charge liability

2.3.31 Demand TNUoS is paid by suppliers and large directly connected customers. Suppliers can manage their portfolio to reduce their liability for demand TNUoS by reducing their net demand at the time of Triad such as by purchasing power from an embedded generator or by encouraging users to reduce their consumption of energy through demand reduction or running onsite generation at the local level to offset their demand from the distribution network.

2.3.32 In this modification, The Original proposals do not propose changes to the way in which NHH tariffs are structured. This is paid by typically domestic customers (through suppliers) and is charged on a p/kWh basis, based on demand taken between 4pm and 7pm over each day of the year. As NHH tariffs are calculated from the HH tariffs, a reduction in HH tariffs such as through a move to gross metering will have a consequential change to the NHH tariffs. In future, the current smart meter rollout means that the changes to HH tariff may apply directly to domestic customers.

2.3.33 A supplier's demand TNUoS charge is based on their net demand at the GSP. Therefore a Supplier reducing its demand will reduce its liability for TNUoS in a given year. Tariffs are set by National Grid to recover the allowed revenue on the basis of net demand on the basis of the forecast of net demand. If net demand falls (though increased embedded generation, or demand reduction) then the unit rate for TNUoS will increase.

2.3.34 Demand Side Response is a term used to distinguish consumer's behaviour whereby demand is reduced when there is a predicted Triad to reduce the liability for TNUoS charges. This is typically done by large industrial or commercial customers who can move demand (demand reduce) or who have onsite generation to reduce the flow they take from the network. The effect of a party Triad avoiding (and reducing net demand) is to reduce its liability for TNUoS tariffs (potentially to zero, if they take no demand), and overall increasing the unit cost for TNUoS as there is now fewer kW of net demand over which the total revenue must be recovered.

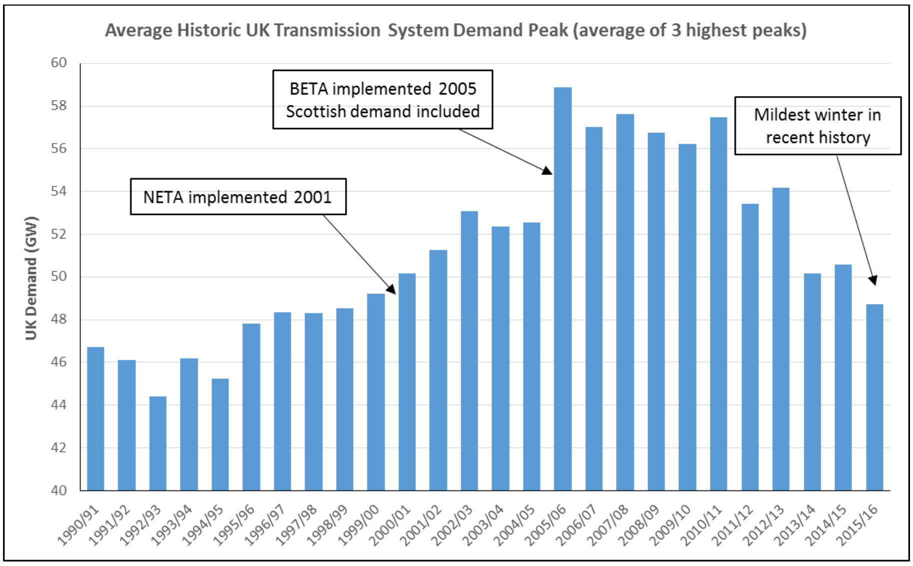
2.3.35 Embedded generation, which exports onto the local distribution network reduces the demand of the distribution network from the transmission network and receives embedded benefits. This embedded benefit is discussed in more detail below.

2.3.36 A 1MW reduction in demand or a 1MW increase in embedded generation has the same effect on the net flow observed at the GSP.

2.3.37 The current mechanism of embedded benefit and Triad avoidance incentivises customers to manage their demand (to reduce charge) and to output embedded generation (to receive embedded benefit). At present, the peak demand on the transmission system is around 49GW. This represents the net position seen at the GSPs; that is to say the sum of all demand from customers on the distribution system less any energy provided from sources on the distribution system (this is both behind the meter generation and "embedded generation"). It is estimated from the 2016 FES scenarios[22] that there is around 7.5GW of embedded generation output at the time of system peak, and 2.5 GW of demand side reduction (either onsite generation or demand reduction; both seen as a reduction at the consumer's meter).

2.3.38 A discussion was held about whether the transmission system could operate if there was no Triad avoidance by embedded generation or demand; although no conclusions were reached – except to note that the system had operated at higher peak than current (see Figure 3). A number of workgroup members noted that this situation of zero demand side response and embedded generation is unlikely to happen as other economic signal, such as the energy price and the capacity market, would incentivise plant to operate. Other Workgroup members disagreed with this viewpoint.

2.3.39 The historic change in the net demand peak on the transmission system is shown in Figure 3.



22 http://fes.nationalgrid.com/

Figure 3: Transmission System Net Peak from KMPG report for UK Power Reserve[23],

2.3.40 The system is secured all year round through the use of ancillary and balancing services by the System Operator (the costs of which are recovered from BSUoS). This ensures a stable, reliable system with voltage, frequency and other technical parameters closely controlled.

Future and Historic Value of the Demand Residual

2.3.41 In considering the historic demand residual, we look back to 2005/2006 charging year when the last significant methodology change happened. In 2016/17, generation tariffs were set under the Project Transmit methodology (CMP213) for the first time, and in 2015/16 the 27:73 split was modified by the €2.50/MWh cap on generation TNUoS tariffs by Regulation (EU) 838/2010.

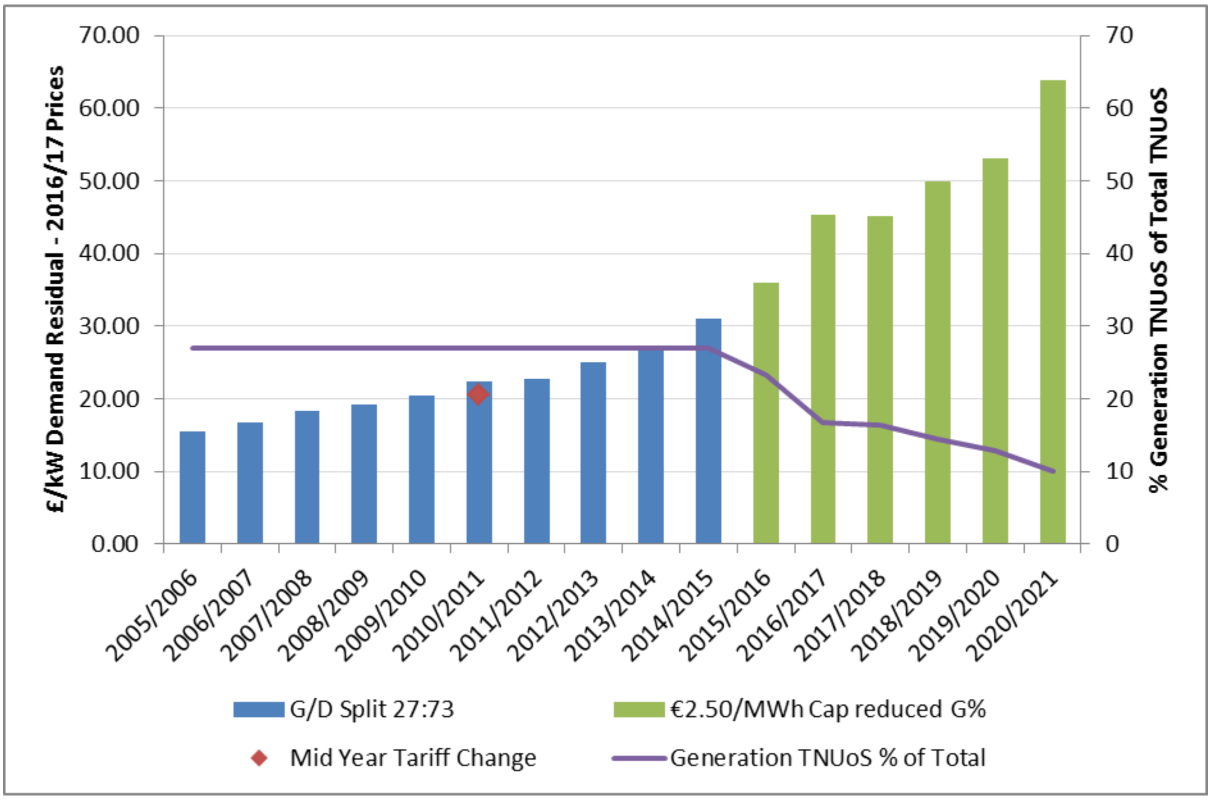


Figure 4: Historic and Forecast Demand Residual since 2005/06

2.3.42 In order to explore the future demand residual further, three hypothetical situations are modelled. It is worth noting that none of these solutions, under the current interpretation of Regulation (EU) 838/2010, set tariffs which are compliant with the €2.50/MWh cap, however, they are included for illustration. The examples are as follows and illustrated in Figure 5:

(a) **Blue – Status Quo.** Demand Residual as shown in the five-year forecast

(b) **Red – G=27%.** The demand residual using the historic 27:73 split for generation and demand TNUoS

23 May 2016: 'The effects of changes to Embedded Benefits on the Energy Trilemma'

(c) **Green – Generation Residual = 0.** Setting the generation residual to zero, meaning only generation locational, local circuits and substation, offshore local circuits are recovered from generation.

(d) **Purple – Generation Residual = 0, and pay 100% of OFTO**. Under the current methodology, offshore generation pay around 75% of the OFTO revenue, and the rest is socialised – and if the generation residual is negative, this is through the demand residual.

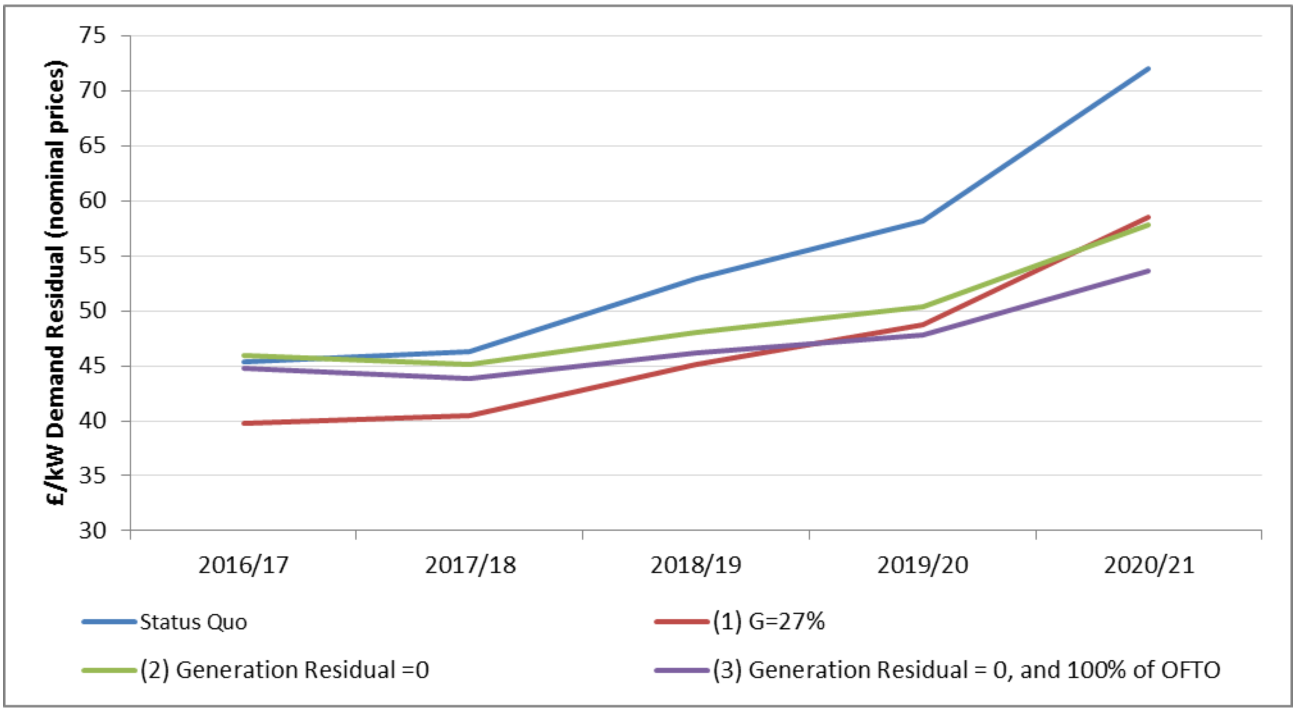


Figure 5: Demand Residual under three hypothetical scenarios

Future total value of the embedded benefit (£m) and how it is paid for

2.3.43 Two recent reports have provided estimates for the total value of the embedded benefit. The KMPG report for UK Power Reserve places a value of £272m for the 2016/17 embedded benefit the Cornwall Energy Review of Embedded Generation Benefits Report for the Association for Decentralised Energy places a value of £293m on the 2015/16.

2.3.44 In additional, for the workgroup National Grid estimated the total value based on the volume of eligible generation outputting at the time of Triad, multiplied by the residual tariff. As gross demand data is not yet available, it is an estimated value based on the data from the FES scenarios.

2.3.45 For 2016/17, the demand residual is £45.33/kW and it is estimated that there will be 7.58GW of distributed generation output at the time of Triad (from the Future Energy Scenarios[24]). This gives a total value of embedded benefit of £343m. This figure can be provide an illustrative value for future year based on the predicated value of the demand residual (from the five-year forecast) and the output of the quantity of embedded generation at Triad.

[24] http://fes.nationalgrid.com/fes-document/ - this particular dataset is not published but is summarised below

2.3.46 The various estimates of embedded benefits are summarised in in Table 5 and Figure 6.

	Charging Year	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Demand Residual	£/kW	35.99	45.33	45.17	49.92	53.15	63.81
National Grid Analysis based on FES							
Embedded generation output at Triad	GW	7.28	7.58	8.28	9.32	9.90	10.18
Estimated value of the Embedded Benefit	£m	262.1	343.4	374.2	465.2	526.3	649.7
KMPG report for UK Power Reserve							
Estimated value of the Embedded Benefit	£m		272				
Cornwall Energy Review of Embedded Generation Benefits Report for the Association for Decentralised Energy							
Estimated value of the Embedded Benefit	£m	293					

Table 5: Total value of the TNUoS embedded benefit (16/17 prices)

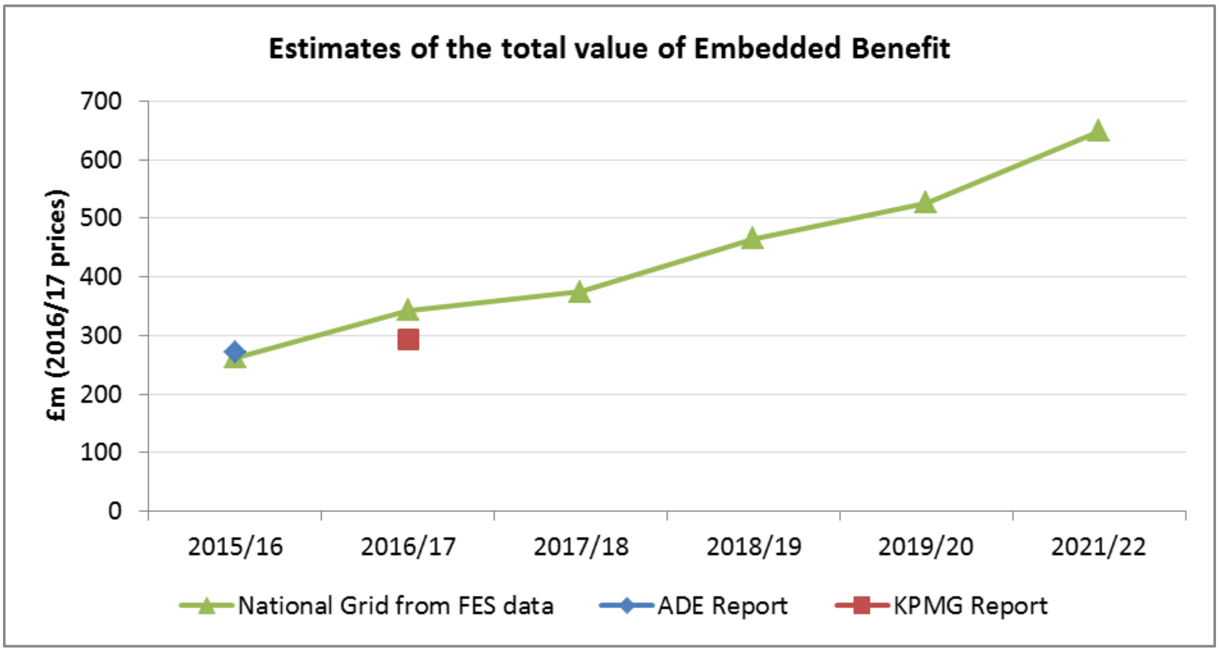


Figure 6: Total value of the TNUoS embedded benefit (16/17 prices)

2.3.47 Within the workgroup there was discussion around how this total value of the TNUoS Embedded benefit was funded. From a charging methodology perspective, with the exception of the c£20m in embedded benefit paid to CVA registered embedded generation, the value of the embedded benefit is not directly recovered via the TNUoS charge. There were two models proposed – firstly, that the suppliers recover network charges from a larger charging base, i.e. their gross metered data, which means they recover additional monies compared to the TNUoS bill from National Grid. This additional money, recover from consumers, is then used to pay the embedded benefit to embedded generators. A workgroup member gave a view that suppliers will retain typically between 5% and 15% of this additional money depending on the agreement of the supplier and the generator; another workgroup member suggested a lower figure or that there was an explicit management fee.

2.3.48 Another model proposed is that the cost of embedded benefit to a supplier is just that, another business cost, and for business decisions it will be treated holistically as part of the business's annual costs. In this sense, it is not necessary directly recovered from customers but may be offset due to other decisions based on the portfolio of customers that make up a suppliers demand TNUoS charge.

2.3.49 Under both models the individual supplier's TNUoS liability will be reduced as a result of the embedded generation and the embedded generator will receive the lion's share of the saving. One workgroup member suggested that both the models essentially describe the same approach. The issue of whether or not a supplier passes any element of its cost base, at any particular time, to consumers is determined not only by its costs but by competitive conditions and the supplier's strategy. On this view, such strategic and competitive decisions are not a consideration for these modifications.

2.3.50 At the workgroup members disagreed on which model was appropriate and it was suggested that there is evidence that both models are used by different suppliers. Therefore, the total value of the embedded benefit may not be recovered directly from customers for some suppliers in the short term. Workgroup members are interested in understanding the views of a range of suppliers further regarding how embedded benefits are paid to embedded generators and are funded.

Consultation Question 9: Applies to both CMP264 and CMP265

i) Suppliers: In setting charges for your demand customers, do you charge them at the same tariff as National Grid charges you (i.e. gross), to enable you to pay the embedded benefit to embedded generators, or please explain the way in which it is funded?

ii) Suppliers: Does the estimate that 7.58GW of embedded generation output and 2.5GW of demand side reduction at the time of Triad for 2016/17 seem reasonable based on your knowledge of the UK market? If not what is your estimate of embedded generator output and DSR at time of Triad?

Suppliers may send this data confidentially to National Grid as a separate response; this will be shared with Ofgem. This will be shared with the workgroup members only as anonymised data.

2.3.51 In the Authority meeting minutes[25] from 23 June when they discussed Ofgem's review of embedded benefit, and noted that "*This [embedded] benefit was substantial, and the amounts saved by suppliers were still ultimately borne by consumers as the total costs of the transmission network still needed to be recovered from customers*."

[25] https://www.ofgem.gov.uk/system/files/docs/2016/07/minutes_23_june_2016.pdf

2.3.52 The Workgroup notes that embedded generation and DSR help reduce the net demand which supports the system at peak. Some workgroup members noted their views that the incentive have grown to be 'too strong' for embedded generation and continue to increase. The proposer of CMP265 gave a presentation to the workgroup arguing that the demand residual charge element is not cost-reflective, unlike locational charge elements, but is an artifice to ensure that the correct amount of revenue is collected. The presentation argued that there is no clear rationale for effectively paying the demand residual charge element to embedded generators. The latter, is possibly could be resulting in existing transmission generation closing and new transmission generation not being built.

Access to Market

2.3.53 Transmission-connected generators and those larger, licensed distribution-connected generators have network and market access not available to smaller, license exempt generators connected to the distribution network. A license exempt generator is not usually a party to the CUSC, the BSC, or the Grid Code, and does not have a bilateral contract with the Transmission Operator or access rights to the transmission network, or direct access to the wholesale market or the Balancing Market. For example, in the Balancing Market, transmission-connected assets have BM units and can offer a Bid/Offer, but most distribution-connected assets do not have their own BM Unit and are reliant on a licensed supplier to create a BM Unit and create those Bid/Offer. The BM is therefore viewed by some Workgroup members as being mainly for Transmission connected generators. This also means, however, these generators do not have the obligations related to these different codes and markets.

2.3.54 An embedded generator can access these markets through a licensed supplier, or can go solo, although their relatively small size makes it challenging to find commercial arrangements with suppliers to access peak prices and relatively high transaction costs remove potential value from doing so. One member made the point that a distributed generator can choose to sign a BEGA[26] and/or join the BSC, although few, have done so. This is due to the significant regulatory cost impact relative to their size, including the cost of moving meters and the increased or additional costs of registering metering in CMRS, becoming a Party to the BSC and complying with BSC Credit Requirements, and a potential lack of liquidity for small clip sizes when hedging in the marketplace. Some members argued that small generators and suppliers may use Triads as a form of income by reducing exposure and market risk, rather than the energy market providing a correction to these alleged market failures.

2.3.55 One member's view is that, if a generator is in fact able to provide a valuable service, there are many existing aggregation business models and opportunities which should allow the service to be provided and the generator remunerated accordingly. It would be important to distinguish between access issues and inability to provide the service cost effectively. If market access remains an issue, despite the specifically targeted work over recent years, the member's view is that a non cost–reflective charging regime should not be viewed as a credible solution that levels the playing field. Other members noted that they did not agree with this view, and that there are barriers to accessing the market for smaller parties. It was further noted by another workgroup member that Ofgem had recognised that the small suppliers had market access issues, in part because small generating companies did not access the market to sell small clips.

2.3.56 Overall the arrangements for access to the market are different for transmission and distribution connected generators. There were a range of views on whether the markets at present are appropriate.

[26] BEGA – Bilateral Embedded Generation Agreement

Previous work in this area

2.3.57 There have been other reviews of embedded benefits which the reader may find useful to refer to:

(a) **National Grid review of embedded benefits:** http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Embedded-Benefit-Review/,
and the **joint industry response:** http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=32671

(b) **Cornwall Energy Review of Embedded Generation Benefits Report for the Association for Decentralised Energy**
http://www.theade.co.uk/medialibrary/2016/05/16/09ca4432/A%20review%20of%20Embedded%20Generation%20Benefits%20in%20Great%20Britain.pdf

(c) **KMPG report for UK Power Reserve.**
http://www.ukpowerreserve.com/media/01062016-press-release-uk-power-reserve-commissions-kpmg-report-embedded-benefits/

(d) **Ofgem on embedded benefits**
See Section 2.17 of Ofgem's Forward Work Plan 2016/17
https://www.ofgem.gov.uk/publications-and- updates/forward-work-programme-2016-17

See also, page 3 of the following Authority minutes:
https://www.ofgem.gov.uk/system/files/docs/2016/07/minutes_23_june_2016.pdf

(e) **DECC recent note on embedded benefits**
The DECC Capacity Market consultation referred to a concerns that the charging arrangements for embedded generators may over-reward embedded generation, which could be having an increasing impact on the energy system, by potentially distorting investment decisions and leading to inefficient outcomes in the CM.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/504217/March_2016_Consultation_Document.pdf

3 Impact of the Proposal and Workgroup Discussion

3.1 Summary

3.1.1 This section contains six sections as follows:

(a) A summary of the workgroup discussions applicable to both modifications
(b) Specific topics for CMP264
(c) Specific topics for CMP265
(d) Impact analysis for CMP264
(e) Impact analysis for CMP265
(f) Note on the technical implementation
(g) Impact on industry and market parties
(h) Possible variables for alternatives

3.2 Workgroup Discussions

Scope of the Defect

3.2.2 There was discussion at the workgroup on the scope of the defects. Two views of the defects were presented: a *narrow* view that is that is the value of the embedded benefit received by embedded generator; and a *broader* view that it is the value of the embedded benefit *and* the way in which it is realised.

3.2.3 The solutions identified in the modification proposals both identify a *narrow* defect, and present solutions to change the value of the embedded benefit for some categories of embedded generation.

3.2.4 In the broader view of the defect, the charging base for demand HH TNUoS would also be up for change as part of an alternative to either CMP264 or CMP265. In this context changes could be made to the definition of Triad, and to the definition of chargeable volume.

3.2.5 Within the workgroup, members expressed a range of views as to the scope of the defect. At this stage, the workgroup has not agreed on a definitive view of the defect and has included discussions which cover both the size of the embedded benefit and the way in which it is realised.

Cost reflectivity of TNUOS relating to Demand Charges

3.2.6 The defect identified by the proposers of these modifications is that the Triad avoidance benefit is non-cost reflective. An understanding of the different tariff elements which arise from the current ICRP charging methodology and applying lessons learned to the way TNUoS demand tariffs are applied helps to explain these views.

3.2.7 **Principles of cost reflectivity, efficient competition and discrimination.** It is a key principle of the TNUoS charging methodology that the charges should be cost reflective. The applicable CUSC objective regarding cost reflectivity is that "…the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs… incurred by transmission licensees in their transmission businesses…".

3.2.8 Use of system charges provide economic price signals which influences the decisions made by network users regarding investment decisions to build a new asset, or close old assets, as well as dispatch decisions regarding whether or not to increase, or reduce generation or demand in particular market circumstances. In the absence of market distortions, if these price signals are cost reflective, then the decisions which users make in response to those price signals will be aligned with market efficiency. It is therefore considered necessary for economic price signals to be cost reflective for truly competitive markets to function effectively and deliver an outcome which is economically efficient. Outcomes which are more economically efficient result in a lower cost to society, which will result in lower cost to customers over time. By contrast, assuming an otherwise perfectly competitive and efficient market structure, if the charging regime is not cost reflective, then it will fail to provide appropriate price signals which will ultimately result in a less efficient system and higher cost to customers. This is because non cost reflective prices will distort competition, so network users will make decisions which are not aligned with the interests of society and are out of economic merit regarding investment in new assets, closure of old assets and dispatch decisions. It is important that this concept does not account for any distributional impacts (which consumers are better off) and relies on the assumption that there are no other market distortions moving in potentially different directions. In other words, it is possible that, when looked at broadly across the entirety of the industry, that cost reflectivity in a narrow area is not automatically the best outcome for consumers.

3.2.9 The importance of this is reflected by the CUSC objective regarding effective competition and cost refelctivity which states:

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

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

3.2.10 The cost reflectivity of system charges has important implications from the point of view of legal discrimination. It follows that with regard to applying different TNUoS charges, or the avoidance of those charges to different groups, it is discriminatory to treat like cases differently. Some Workgroup members have pointed out that this proposal does not include onsite embedded generation and true demand side reduction is not impacted by these modifications, therefore it could be argued this proposal is selective discrimination against embedded generators as a subset of demand.

3.2.11 The principle of cost reflectivity is incorporated into section 14 of CUSC, paragraph 14.14.6 of which states:

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

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

3.2.12 The transmission owners (TOs) invest in their networks in order to meet security of supply standards (SQSS) incurring costs as they do so[27]. The cost reflectivity of the TNUoS tariffs is determined by a locational element calculated according to the Investment Cost Reflective Pricing (ICRP) methodology using the Direct Current Load Flow (DCLF) Transport model which is a reflection of the SQSS. TOs actual spend is regulated by Ofgem and an annual revenue amount is determined with each price control period, the Tariff model therefore sets tariffs in order to recover this allowed revenue amount.

3.2.13 The SQSS was changed in 2011 and the new investment criteria were implemented into the ICRP charging methodology under Project TransmiT (known also as CMP 213) the effect being to introduce a locational Peak Security tariff element and a locational Year Round tariff element (see 3.2.16) for both Generation and Demand.

3.2.14 The Project TransmiT decision included a new approach to more appropriately apply these new tariff elements to generation TNUoS tariffs, however at the time, those changes were not carried through to changes in the way demand TNUoS tariffs are applied.

3.2.15 **How the TNUoS ICRP charging methodology deals with cost reflectivity.** The ICRP methodology uses the principle that the transmission investment cost caused by (or avoided by) a network user on the transmission network is a function of the change in power flows on the transmission network as a result of their use of the transmission system. This is because a change in power flow on a particular circuit contributes to a greater, or lesser need for additional investment to reinforce that circuit. If a user causes an increase in the flow on a particular circuit, then the cost of that circuit contributes to an increase in that user's TNUoS, while by contrast, if the user causes a reduction in the flow on a circuit then that particular circuit contributes to a reduction in that user's TNUoS charge.

3.2.16 **How the charging methodology is reflected in the TNUoS tariff elements.** The TransmiT changes resulted in the introduction of new tariff elements which provide a cost reflective price signal to reflect the cost caused by different types of network users due to their different impacts on network flows at different locations and under different network conditions. These new locational elements were:

(a) Peak Security - Tariff element which reflects the SQSS Security Background criterion

(b) Year Round - Tariff element which reflect the SQSS Economy Background criterion

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27 "Transmission Owners' investment decisions must be based on a document known as the SQSS . This contains standards which they should follow when developing the transmission network (e.g. when seeking to ensure that the conduits for electricity are sufficient to carry electricity to and from the appropriate places). The SQSS identifies the required capacity for the transmission system; Transmission Owners invest in order to deliver that capacity." National Grid witness statement as part of the TransmiT Judicial Review process

3.2.17 In addition, Project TransmiT also changed the charging base definition by which these new tariff elements are applied to generators (introduction of ALF and exclusion of intermittent generators from paying the Peak Security element). However, the defect identified in both of these mods exists because the definition of the demand charging base used to apply these new post TransmiT tariff elements has not been correspondingly updated to take account of these new tariff elements, but instead remains the unchanged Triad demand definition. The difference is that the generation charges takes a cost reflective approach by using a different definition of charging base for each tariff element, while by contrast the demand charges simply adds them all together and applies them all to the same demand charging base.

3.2.18 The Demand Residual was unaffected by the Transmit Changes. This element remained as simply a mechanism for adjusting the TNUoS demand charge so that the charges collect the appropriate total amount of transmission owners' revenue from demand. The demand residual is therefore a non-locational, non-cost reflective balancing item and may be considered equivalent to a form of taxation with the purpose of raising revenue from demand for sunken costs. In this sense, it is not cost reflective although the money raised is used to fund various costs associated with building, maintaining and running the transmission network such as depreciation, return, direct and indirect operating costs or non-avoided costs.

3.2.19 These four elements of the demand TNUoS tariff are broken down in the table below. This table was published by National Grid in their quarterly forecast update of TNUoS tariffs for 2017/18 on 30th June 2016, table 27.

Zone	Zone Name	Peak Security Tariff	Year Round Tariff	Residual	Small Generators Discount	HH Demand Tariff (£/kW)
1	Northern Scotland	2.41	-20.02	47.68	0.62	30.67
2	Southern Scotland	0.13	-17.82	47.68	0.62	30.60
3	Northern	-2.93	-6.24	47.68	0.62	39.12
4	North West	-1.17	-1.93	47.68	0.62	45.19
5	Yorkshire	-3.07	-0.17	47.68	0.62	45.05
6	N Wales & Mersey	-1.55	0.18	47.68	0.62	46.92
7	East Midlands	-2.11	2.12	47.68	0.62	48.30
8	Midlands	-1.47	2.93	47.68	0.62	49.76
9	Eastern	1.26	0.67	47.68	0.62	50.22
10	South Wales	-5.69	4.29	47.68	0.62	46.89
11	South East	3.88	1.02	47.68	0.62	53.20
12	London	5.11	2.27	47.68	0.62	55.67
13	Southern	1.80	4.08	47.68	0.62	54.18
14	South Western	-0.76	5.24	47.68	0.62	52.77

Figure 7: Components of the demand tariff from 2016/17 Quarterly Update.

3.2.20 The current demand TNUoS methodology calculates the demand TNUoS tariff for each zone as the sum of all of these four tariff elements which is then applied to the average MW of a customer's demand across the three Triad period half hours. The value of the embedded generator Triad avoidance benefit is equal and opposite to the demand Triad tariff in the relevant charging zone.

3.2.21 **Workgroup discussion of tariff signals**. Ofgem's decision on the implementation of project TransmiT and the subsequent Judicial Review of the decision were identified as significant by the workgroup. Specifically, Ofgem described in their Project TransmiT Decision document[28] the nature of the locational elements of the tariff (including both Peak Security and Year Round elements):

"1.10 …The first is a cost reflective locational element, designed to reflect the impact a generator has on the costs of the transmission network. This is calculated by assessing the impact on the costs of the network of adding a megawatt (MW) of generation or demand at different locations on the system. The resulting impact is converted into a monetary value in the tariff by using the average cost of building the existing network circuits at current costs."

3.2.22 The generation and demand tariffs use a different definition of charging zones which results in differences in the locational tariff elements between generation and demand. However, if the definition of zones were the same, then the relevant generation and demand locational tariff elements would have equal, but opposite values because the effect on energy flows of generation and demand is equal and opposite.

3.2.23 It was noted by one workgroup member that generation / demand are not always able to respond to locational signals due to a lack of available connection capacity and the signals would influence new plant, but not existing plant or customers.

3.2.24 The purpose of the Demand Residual tariff element is not to provide a locational price signal (which is achieved via the locational tariff element), but to recover the bulk of the costs that relate to the existing transmission network such as depreciation, return, direct and indirect operating costs. Some workgroup members believe It could therefore be described as a form of 'taxation' aimed at collecting the revenue required to pay for a 'public good' delivered to all consumers ("demand") as they benefit from the existence of the transmission network.

3.2.25 The Workgroup held a discussion around the societal benefit from having a national transmission system. It was the view of some workgroup members that society (customers) obtain an economic benefit from having a transmission system, which reinforces the principle that it is appropriate that society/customers (final consumption) pay for it on an equitable basis such as through the TNUoS Demand Residual. This was noted by some Workgroup members as an important point when considering the impact or value generation connected at distribution has on the Transmission System i.e. Embedded generators do not replace these societal benefits from having a transmission system, so it is not appropriate to pay a benefit to embedded generators as if they do. One Workgroup member noted that the 2010 Seven Year Statement included a discussion on the benefits of a transmission system[29].

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

[29] 2010 NETS Seven Year Statement: Chapter 6 – The Transmission System p8 http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/Electricity-ten-year-statement/SYS-Archive/

3.2.26 Workgroup members expressed different views on the application of a demand TNUoS 'credit' to embedded generators. Some felt that the avoidance of paying the Demand residual was a distortion to the effective functioning of competitive markets as it was akin to 'tax avoidance'. Another view is that the marginal locational element sets the relative cost signals between the charging zones but does not fully value the benefits that embedded generation bring to the transmission network. The residual element recovers the bulk of the costs that relate to the existing network such as depreciation, replacement of existing assets return, direct and indirect operating costs. National Grid was unable to provide analysis of the different costs which make up the residual charge within the Workgroup's time constraints. Balancing demand and generation locally at all times reduces the need for bulk power transmission. Embedded generation will reduce the requirement for these costs over the longer term and the savings that will be achieved from the increase in embedded generation will be realised in future price controls.

3.2.27 One Workgroup member noted that the avoided transmission network costs that are attributable to embedded generation should therefore reflect those elements of the residual that can are avoided by embedded plant in the long term, taking account of the typical life of an embedded plant, plus the likelihood that the existing connection will be reused by a replacement plant once the existing plant reaches the end of its useful life. An alternative view, presented during the Workgroup, is that the effect on the transmission system of connecting generation in a particular zone is the same whether it is embedded, on site generation, or transmission connected generation.

3.2.28 Some workgroup members believe the rationale, in the current charging methodology, behind the Triad avoidance embedded benefit is that embedded generators use the transmission network in a way which is equivalent to negative demand, so TNUoS charging should expose them to a locational economic price signal which is equivalent to the negative of the locational demand charge. This is based on the principle that for a particular type of generator, the impact on network power flows is symmetrical between an increase due to new investment, or reduction due to closure of capacity and there is an equal and opposite impact on flows between changes in capacity of generation and changes in demand at the same location.

3.2.29 The justification for this treatment is that the value of the benefit to the embedded generator should reflect the value of the avoided transmission network cost which that embedded generator causes. Therefore the value of the embedded benefit should reflect the change in network flows caused by that embedded generator at a particular network location. As discussed above, some workgroup members also believe the value of the embedded benefit should reflect longer-term costs avoided which are currently recovered through the residual charge.

3.2.30 The was some consensus within the workgroup that the forecasted increasing size of the demand residual and compatibility of new embedded generation through the capacity market meant that there was little evidence that the current calculation of the Triad avoidance benefit for either distributed generation or demand users, would remain appropriate for the future for demand and embedded generation.

3.2.31 **Incremental Impact on Transmission Costs.** A Workgroup member presented to the Workgroup views on the incremental impact on transmission costs (as collected by suppliers and the National Grid) resulting from the connection of 100MW of various types of distributed generation. The details of which can be seen in Appendix 7, section 7.7.

3.2.32 A number of points were presented by the Workgroup member which are detailed below (note that numbers use reflect the example figures in the appendix) suggested that:-

(a) For all four options the flows on the **transmission are the same at 900 MW import**. So the effect on the transmission system of connecting embedded, on site generating, DSR or transmission connected generation via the same GSP is the same.

(b) Funding for supplier embedded benefits is collected from the difference between the suppler and the transmission demand changing base multiplied by rate (TNUoS tariff), this funding is shared across all demand customers equally.

(c) The **incremental transmission cost** to consumers resulting from connecting additional 100MW of embedded generation via the supply embedded route is £5.18m this results from a reduction in the transmission demand charging base (creating a higher tariff) that is then collected over the larger supplier charging base. This is more than £4.55m than might be expected, as the higher tariff is collected over all embedded generation and not just the additional 100 MW this creates an addition £0.63m of cost. It should be noted that there is no way to know how suppliers distribute these charges or what competitive market positioning they may choose.

(d) The **incremental transmission cost** to consumers resulting from connecting additional on Site/DSR is £0.63m, the tariff is the same as the supplier embedded generation but the supplier charging base is 100MW smaller.

(e) The lowest **incremental transmission cost** to consumers is 100 MW of transmission connected generation at the GSP this results in no change to costs faced by consumers and does not change the supplier or the transmission demand charging base.

(f) The Workgroup member postulated that on site generation and DSR were different in character to supply embedded generation. With onsite generation/DSR the lower supplier transmission cost was seen directly by the **demand host,** although the situation of a third party generator onsite was also briefly mentioned. The benefit could be used to reduce demands as long as the cost of reduction did not exceed the benefit of reduction. With supply embedded generation there is an increase transmission cost demonstrated within the model presented to the workgroup that is seen by all consumers subject to Suppliers' strategic objectives.

(g) The Workgroup member suggested that one solution would be to apply Generation TNUoS to transmission generation and embedded supply generation with National Grid collecting demand TNUoS based on gross demand metering. Some members of the Workgroup did not support this suggestion.

3.2.33 Other Workgroup members disagreed that there was any difference in the impact embedded generation and on-site generation/DSR on their impact on transmission network costs. Another Workgroup member argued that transmission-connected generation should not get the same transmission network cost signals as embedded generation, as embedded generation does not use transmission network assets, and should be seen as negative demand that reduces overall transmission network demand, and therefore is rightly recognised for avoiding the transmission network demand charge. This Workgroup member argued that the difference in value between the embedded and transmission-connected generator also reflected:

(a) The difference in charging between generation – based on capacity – and demand – based on peak demand

(b) The European cap on generation transmission network charges, which increases the share of the demand residual relative to generation

(c) A share of the demand residual not being demand related, leading to less cost-reflective recognition for demand reduction

3.2.34 The Workgroup member went on to present a short summary of the difference between DNO zones and GSP nodes. DNO zone 7 (East Midlands) contains around 30 individual Grid Supply Point (GSP's) where power can flow on and off the 400 kV system referred to as nodes. Some of the nodes serve generation, some serve demand and some both. In general bulk power flows in the UK are from North to South/ This increasing generation (or reducing demand) in the North increase North South flows. The current demand tariffs are based on the demand weighted GSP. The zonal tariffs are in principle determined by looking at the change in flows by adding a MW of generation at each node (MWkm). As the East Midland zone is roughly in the centre of the UK generation map some nodes have a positive locational tariff and some a negative one. The Workgroup member pointed out that the locational tariff was dampened significantly by the size of the demand TNUoS zone. Generation TNUoS zones typically contain fewer nodes and have sharper tariffs. Refer to Figure 19 in section 7.7.4 for further information.

3.2.35 **Typical funding arrangements for connection of transmission and distribution connected generation.** A Workgroup member presented typical funding arrangement for connection of transmission and distribution connected generation. This is represented in Figure 21 in Appendix 7. Transmission connected generators typically own and fund all equipment (1) including the 400kV switch. A skeletal 400 kV bay (6) is typically provided by the TO (included in TNUoS) to connect to the transmission system at £10-30/kw for a 500 MW connection. As this connection is funded by TNUoS it is not directly paid for by the generator but funded by all customers.

3.2.36 Distribution connected generators face similar charges, in that they pay for their own works (2) fund sole user works (3) and a share of reinforcement (4), (5). In general no works are required to the distribution connection (7) to the 400 kV system except in the case of exporting GSP's connection when funding is typically included in TNUoS.

3.2.37 One Workgroup member pointed out that there was a difference between the WACC (Weighted average cost of Capital) of a company and that of the distribution/TO companies that lead to difference in cost between TO/distribution funded works and generator's own works depending on the specific circumstances. Another Workgroup member considered that the WACC will vary from project-to-project, company-to-company and over time depending on circumstances. The Workgroup member does not believe that these arguments are significant within the context of the scale of the distortion that the proposed modifications seek to address.

3.2.38 One Workgroup member disputed the assertion that the funding arrangements for the connection of transmission and distribution connected generation are very similar. One central difference is that distribution connected generators must pay for 100% of their Sole Use assets and their allocated proportion of reinforcement charges as capital payments in advance of energisation. In contrast Transmission Connected generators only place securities in advance of connection – facing liabilities on termination and pay off any of their sole use assets on an annuitized basis through the economic-lifetime of the connection assets. Separately, it should be acknowledged that the 'share of reinforcement' is variable. There are circumstances where embedded generators must fund the reinforcement works that they trigger in full.

3.2.39 **Types of harm caused by the defect of the non-cost reflective Triad charge as discussed by the workgroup and representing the views of some workgroup members.** Both proposals CMP264 and CMP265 identified that the Demand Residual tariff element as the primary reason why the current Triad price signal is not cost reflective. Both proposals also identified that the resulting Triad avoidance behaviour is economically inefficient as demonstrated by distortions which it causes to competition in the Capacity Market and new investment decisions. The types of harm caused by this non cost reflective Triad avoidance behaviour were described to the workgroup in the following terms:

3.2.40 **Triad avoidance by embedded generators:**

(a) Type 1: Inefficient investment/closure – Decisions taken by embedded generation – If the payment of the Demand Residual avoidance tariff is not cost reflective, it distorts the market competition for investment between different generation projects. Because of this distortion, generation projects will be developed out of economic merit, so more expensive projects in receipt of non-cost reflective Triad benefits will be able to attract investment ahead of projects that might be better value should they receive the same Triad benefit. It is argued that the scale of the Demand Residual avoidance distortion is so large that it overwhelms other types of economic price signals which generators would otherwise compete on such as location, capital cost and marginal cost of generation. And therefore this defect would tend to result in worse economic efficiency for the energy system, worse social welfare and ultimately higher costs to consumers.

(b) Type 2: Inefficient dispatch - Decisions taken by embedded generation - When an embedded generator chooses to generate to earn the Triad avoidance payment this can result in the embedded generator dispatching out of economic merit. As the three Triad half hours become increasingly difficult to predict and the reward for Triad avoidance becomes increasing valuable to embedded generators, then the number of hours during which embedded generators will have to generate to secure their Triad avoidance payment is likely to continue to increase. This distortion to economic dispatch may mean embedded generators with higher marginal cost dispatching out of merit and displacing other more efficient and hence lower marginal cost generators. As the Triad half hours will always coincide with the time of peak demand in the system, then these will be periods of very high marginal cost and therefore most available plant would expect to be running and in merit. The ultimate consequences could be a higher total cost of generation for the system, higher total fuel consumption, weaker national fuel security and higher carbon emissions, all of which could feed through to higher costs to consumers. One Workgroup members noted that there are other reasons why plant may dispatch out of merit such as STOR calls.

(c) Type 3: Discriminatory redistribution of transmission costs between customers and generators - Irrespective of how much Triad avoidance takes place, the full demand share of total sunk cost of the Transmission network still has to be collected from customer bills. Meanwhile, the existence of competitive markets means that the value of the Triad avoidance is largely paid to the Triad avoiding generators (the group discussed how this substitutes the suppliers' avoided TNUoS liability with Triad avoidance payments to generators instead). Some members of the workgroup proposed that this results in the Triad avoidance benefit imposing an additional cost to customers because customers have to pay for the value of the residual Triad avoidance benefits paid to embedded generators on top of the total cost of the Transmission network which they have to pay for.

(d) Type 4: Discriminatory redistribution of transmission costs between generators - Because Triad benefit, which embedded generators are being paid to avoid the Demand Residual, is not considered cost reflective, the payment represents a monies paid to embedded generators, but not to transmission connected generators. The current charging methodology treats two groups of generators differently even though they may be providing the same service of generating at the times of Triad. Therefore the current charging methodology is discriminating in favour of embedded generation and against transmission connected generators. Arguably, embedded generators obtain an unfair competitive advantage; therefore they are able to earn additional profits to the detriment of transmission connected generators.

3.2.41 **Triad avoidance by demand** (behind the meter generation, DSR, or demand reduction):

(a) Type 1: Inefficient investment/closure – Behind a demand meter - Because the price signal to avoid paying the Demand Residual on the Triad is not cost reflective, it distorts customer investment decisions. It creates an incentive for customers to spend money on equipment, services, or other capabilities to avoid Triads which cost more than the benefit to the network it provides. The scale of this price signal could be overwhelming other types of economic price signals which customers would otherwise take into account such as location, capital cost and marginal cost of demand reduction. This defect will tend to result in lower economic efficiency for the system, lower social welfare and ultimately higher costs to customers.

(b) Type 2: Inefficient dispatch - Behind a demand meter - When a customer chooses to engage in DSR by adjusting their demand profile to avoid paying Triad charges, this can result in the DSR dispatching out of economic merit. This means that the marginal cost to the customer of taking the avoidance action can be greater than the marginal benefit to the transmission network. Depending on its location, a customer's Triad avoidance action may increase the investment cost of the transmission network. As the three Triad half hours become increasingly difficult to predict and the reward for Triad avoidance becomes increasing valuable, then the number of hours which customers will have to take avoidance action to be confident of avoiding their charge will continue to increase. This distortion to economic dispatch may result in higher marginal cost DSR dispatching out of merit and displacing lower marginal cost generation. This could result in a higher total cost for the system and higher cost to customers.

(c) Type 3: Discriminatory redistribution between customers - Currently, sophisticated customers who are half hourly metered and have the resources to do so are able to take action to reduce their demand at periods of Triad and in this way they can substantially avoid having to pay for the cost of the transmission network. These sophisticated customers can continue to use the transmission network and receive benefits from it at all other times. Because the avoidance of the TNUoS Demand Residual is not cost reflective, the avoidance of this customer charge does not represent any actual avoided cost to the transmission network. This discriminates against non-half hourly customers and more vulnerable, or less sophisticated customers who are less able to take action to avoid Triad charges, so are therefore forced to subsidise the use of the transmission network by other more sophisticated customers.

3.2.42 The types of harm which follow from the non-cost reflective nature of Triad avoidance which applies to both embedded generation (whether it is behind its own meter, or hidden behind a demand meter) as well as action behind a demand meter (which may also include generation, DSR, or demand reduction). These are consistent with the defects identified within both CMP264 and CMP265 and do not represent the views of all workgroup members:

(a) **Distortion to the Capacity Mechanism new investment / closure decisions –** The value of Triad avoidance improves the competitive position of two select groups of market participants namely embedded generators and DSR. Therefore the behaviour of both of these groups may distort the outcome of competitive Capacity Mechanism auctions which they can both participate in. However, it should be recognised that existing embedded generators are classed as price takers as are existing transmission connected generation and this was specifically designed to reduce distortions in the capacity market auctions from existing generators given the wide range of technologies and dates/returns of previous capital investment. Moreover, it should be recognised that all plants competing in the Capacity Mechanism have various and different sources of revenue all of which could be seen as distorting the outcome of the Capacity Auction.

(b) **Distortion to the wholesale power price** – The value of Triad avoidance provides an incentive for both embedded generation and DSR to dispatch out of merit in the wholesale power market, therefore both of these groups potentially distort the clearing price of the wholesale market. However, running for Triad will typically be for less than 100 hours in a year - or a load factor of less than 1%.

3.2.43 For the avoidance of doubt the types of harm outlined above are not the views of all Workgroup members.

DSR and Behind the Meter

3.2.44 Demand Side Response (DSR) is the term used to refer to customers who load shed all or part of their load. If a customer can load shed through the Triad periods they avoid the TNUoS charges. This "Triad avoidance" was originally introduced under the CEGB, as the customers reducing peak demand reduced investment in the transmission and distribution systems and helped reduce the need for expensive energy. Since privatisation the arrangements have evolved, but the basic principle has remained and Suppliers will not be charged for the demand if it is not there on the three Triad periods and will not therefore charge their customers.

3.2.45 National Grid explained that they had concern that with increasing HH metering the amount of load that could do Triad management was increasing and there was a risk that a smaller customer base would become liable for the increasing cost of transmission. While National Grid has been considering this issue in its own transmission charging review, the group noted that it may become necessary for some charges to be applied to all customers who in the course of a year may use the network. However, it was not clear that if the Triad incentive was removed, or substantially reduced, what the impact on the DSR volume would be and whether National Grid's system could accommodate the potential change in flows. One Workgroup member highlighted that CMP264 only looks to address new embedded generation, and therefore any impact on existing DSR and embedded generation will be minimal. The broader question is one to be looked at in the context of a wider review of charging.

3.2.46 The group discussed the difference between DSR, which is avoiding the TNUoS, and embedded generation which is largely paid some Triad benefit. Some suggested this treatment was discriminatory, though acknowledged that the exact commercial relationship is a matter for each party's supply agreement. Others felt it was not discriminatory as the customers were avoiding a cost, where an embedded generator had costs from generating (fuel, carbon, etc.). However, there was agreement that DSR or generation would have an equivalent impact at a GSP on the transmission network. As well, the price signal per kW is identical for a customer reducing demand to avoid TNUoS or exporting embedded generation to receive the Triad benefit.

3.2.47 Behind the meter generation is where a customer has generation on their site, which may then invisible to the network companies. This generation may be used by the customer continually or only at certain times. The size of the generation relative to the customer's demand and the way it operates can vary, but they fall into a number of groups as shown in Table 6.

Behind the meter configuration	Daily network flows	Triad Response	Probable financial impact
Demand = Generation	Customer use of networks limited, but probably has connection as back up	May cut demand at Triad and export power	Similar to embedded generation and likely to receive Triad benefit
		May do nothing at Triad as no import will attract no TNUoS charge	Is almost "off grid" and likely to not pay TNUoS, not be paid Triad
Demand>Generation	Customer uses networks for imports	May still cut demand at Triad to export	Similar to embedded generation and likely to be paid Triad benefit
		May just cut demand and use own generation	See as customer undertaking Triad avoidance
Demand<Generation	Site seen as an export site so same as an embedded generator	May cut demand to increase exports at Triad	Likely to have a PPA with Triad benefit paid

Table 6: Impact of behind the meter configuration

3.2.48 By holding generation behind a meter the generation may be invisible to the central electricity systems. For example, their meters will not be registered into the settlement systems, with only the boundary meter registered. This would allow the generation asset and the customer to share the connection cost, only pay for the net flow use of system charges, etc. As the generation is supplying the customer directly (possibly via a wider private network) the generation output consumed behind the meter is also no subject to charges that are levied by Licenced Suppliers such as the renewables obligation.

3.2.49 In looking at Triad benefits, a generator who uses a customer connection to export during a Triad would be difficult to identify as the settlement meter would be at the customer's meter and not a generation meter. So any change to the way exports on to a DNO network receive (directly or indirectly) could alter the incentive on embedded generators to locate behind a meter on a customer's site. This may not in itself represent any problem, and it could be argued that on-site generation should be encouraged, but it may not have any impact on the quantity of embedded generation participating in the capacity market.

3.2.50 Some of the issues described above will not apply to CMP264, as the proposal is for it to apply to any new or enlarged export meter - regardless if it is associated with local demand. The exception, depending on the final implementation, may be new generation behind an existing export meter (with associated demand) that currently holds redundant export capability. Where there are possible limited exceptions, the proposer expects further reforms may be required as part of a broader review of charging.

3.3 Specific topics for CMP264

3.3.1 The workgroup held various discussions on the particular details of the CMP264 proposal, which are summarised in the following section.

Definition of new embedded generation

3.3.2 The aim of CMP264 is to ensure that parties considering investment in embedded generation plant do not factor in the continuation of non-cost reflective Triad avoidance payments during the period of the expected Ofgem Review, when making its investment decisions.

3.3.3 The proposal is not aimed at solving the bigger question of what should be the appropriate methodology for allocating supplier contributions toward TNUoS costs. All existing generators are at risk of changes in this methodology during the lifetime of the plants, and this issue and any transitional arrangements will be matters for Ofgem and others to consider during the expected review.

3.3.4 CMP264 is therefore limited to New Embedded Generation which is defined as half hourly metered embedded generators which are commissioned after a cut-off date (defined in the Original Proposal as 30 June 2017). Commissioned was defined in the proposal as having an exporting MSID registered and having commenced generation. This section of the workgroup report considers the cut-off date and the definition of "commissioned". In light of discussions the proposer has provided further clarifications of definitions of new embedded generation which are included under 3.3.15.

3.3.5 **Cut-off Date.** The cut-off date should be:

(a) early enough to prevent distortion of future investment decisions and

(b) late enough to minimise the impact on existing investment decisions.

3.3.6 CMP264 was introduced to the CUSC Panel on 27 May 2016. Setting a cut-off date of 30 June 2017 allows Parties a period of 13 months from becoming aware of the proposal to complete construction and commissioning of their plant. This is considered adequate by the proposer given the smaller nature of embedded plant. A later cut-off date may only encourage a late rush to contract and commission plant before such a date. The cut-off date is designed to capture parties bidding in future capacity market auctions, rather than those already holding agreements.

3.3.7 **Commissioning.** Any developer seeking to connect new generation plant[30] to a distribution system must follow the Engineering Recommendation (EREC) G59 process[31] when commissioning new generation. The requirements and tests for commissioning are set out in EREC 59 (Section 12) and the DNO may wish to witness commissioning. On completion of testing, a Commissioning Confirmation Form (CCF) has to be submitted to the DNO within 28 days after the commissioning date. In addition to the plant technical details, the CCF shows details of the MPAN(s) associated with the plant.

3.3.8 The G59 process and CCF should provide sufficient evidence of the commissioning date to enable suppliers to determine whether a New Embedded Generator has been commissioned before the cut-off date above.

3.3.9 Any generation plant in excess of [50kW] which completes the G59 process after the cut-off date and which is connected at a half-hourly metered exporting site will meet the criteria for New embedded generation.

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30 EREC G59 applies to projects with a capacity of more than 16A per phase (if there are multiple generation units connected at the same premises, then 16A or more is the combined capacity per phase); or Projects connected at higher voltage than 230V (single phase), or 400V (three phase); or Any other projects that are not type tested under the requirements of EREC G83.

31 http://www.energynetworks.org/electricity/engineering/distributed-generation/engineering-recommendation-g59.html

3.3.10 The situation when a commissioning date was changed due to a DNO, for example, delivering a connection late was also briefly discussed but no conclusions were reached.

3.3.11 **Long Term Contracts (CfD and CM).** The workgroup considered the issue of whether embedded plant which had secured long term contracts under either the Contract for Difference (CfD) or Capacity Mechanism (CM) auction should be exempt from the cut-off date for New embedded generation. Plant which has secured a CfD or CM contract has met a number of criteria regarding project maturity and the ability to finance the project. One Workgroup member noted that plant securing these contracts will have based its investment decision upon the charging arrangements in place at the time of the respective auction processes including the availability of Triad avoidance payments. Some members highlighted that National Grid had recently concluded a review of embedded benefits in 2014 and decided not to make any changes directly relating to embedded benefit just before the 1st capacity market auction and therefore noted it was reasonable to assume this charging methodology would remain in place for the future and has been in place over 15 years. Importantly both DECC and Ofgem released statements directed at Capacity market participants encouraging them to take into consideration in their CM bid strategy all alternative revenues.

3.3.12 The Proposer has decided not to include an exemption for projects in possession of an existing CfD or CM contract in the Original proposal although they would be willing to see these form the basis of a Workgroup Alternative (see Section 4).

3.3.13 **Mixed Sites.** Mixed sites are those which contain a mixture of demand and embedded generation; and may either be taking energy from the distribution network, taking zero energy (either as there is no demand, or demand is met by onsite generation), or exporting energy on to the distribution network.

3.3.14 In general, if a site of sufficient size is registered as an export site after the cut-off date and the G59 process completed, then any export from that site should be classified as New embedded generation and should not be netted from a Supplier's demand for TNUoS charging purposes.

3.3.15 The default position for CMP264 has been proposed with the purpose of only capturing new export meters, and gross export volumes[32]. Above and beyond screening for the definition detailed under 3.3.4, the proposer believes that there is a requirement to formulate rules for at least the following four outcomes.

(a) **Existing export meter, where demand is reduced and the site exports for the first time or increases export.** In this scenario, the generation plant is long standing, will not require to complete the G59 commissioning process and the generator should not be classed as a New Embedded Generator.

(b) **Increase in generation capacity behind an export meter where there is existing export redundancy.** The connection of additional generating capacity behind an existing exporting meter should require commissioning via the G59 process and should be classified as New embedded generation if commissioned after the cut-off date.

[32] The proposer appreciates that there have been discussions around the possible requirement to capture both imports and exports, and a netting process at each individual site. Whilst it is acknowledged that this could lead to a more accurate solution at a limited number of new sites, the proposer remains unconvinced. Moreover, in the event that it is considered a more robust solution, it is unlikely to prove to be a cost effective solution – especially as the modification is considered temporary and only applies to new sites that may still have the opportunity to reconfigure.

(c) **Increase in generation capacity behind an export meter that creates a requirement for a new export meter.** The connection of additional generating capacity at an export meter should require commissioning via the G59 process and should be classified as New Embedded generation if commissioned after the cut-off date.

(d) **Meter Replacement** Replacement of metering equipment at a mixed site where there is no change to the generation plant connected will not trigger the G59 commissioning process and should not be considered New Embedded Generation.

3.3.16 For scenario b, where BSC metering is not readily available, there is a requirement for the supplier to self-declare the exports from the new behind-the-meter generation during Triad periods. If suppliers are unable supply the relevant information, for all Triad periods, for the new generation plant, the proposed default position is that all the volume, from the existing export meter, will be deemed to have been generated by the new plant and treated accordingly. There may also be a requirement to adopt the same approach for Scenario c, however it may be more cost reflective to install separate new meters for the newly installed generation plant.

3.3.17 The proposer recognises that the same non-cost reflective signals could be driving investment in plant to serve load behind the meter and, given that CMP264 only focuses on exports, this could create a loophole - whereby generation is located so that its output is invisible to the network. However, in practice these sites will be fewer and further between, more difficult to develop and will take longer to come to market. In the context of a temporary solution and against a backdrop of the expected review, we do not expect the impact to be material, or any discrimination to be material.

Consultation Question 10: Applies to CMP264 Only

i) Do you think a cut-off date for “new embedded generation” of 30 June 2017 is appropriate? What other date would you propose?

ii) Do you have any views on how mixed sites are being addressed in CMP264 Original?

iii) Do you think new-build embedded generation capacity that has entered into long term financial and performance commitment obligations via 2014 and 2015 capacity market or contracts for difference auctions (prior to this modification proposal) should be given exceptions to this cut-off date?

iv) Do you agree that ignoring demand behind the meter is unlikely to create a significant “loophole” or material discrimination risk in relation to the CMP264 arrangements in the short term

v) Question to suppliers: Do you consider that the wording of your existing contracts allow you to reflect the changes provided by these modifications in a cost reflective manner. For example, these changes will apply to existing PPAs and generators who significantly alter their output (EREC 59).

vi) Do you agree with the definition of commissioned and do you agree that it is appropriate? If you do not agree with the definition or that it is appropriate please provide alternative definitions and rationale for this definition.

3.3.18 The workgroup discussed how the precise mechanism for determining a new embedded generation would be codified. It was noted that the CUSC is only a contractual relationship between National Grid and suppliers, and that some other form of relationship may be needed between DNOs, suppliers and embedded generators to enforce the definitions of New Embedded Generators.

Start date and CMP244 implications

3.3.19 The workgroup held a discussion around the implementation and the interaction of the change in the TNUoS tariff setting date proposed under CMP244. On 15 July 2016, the Authority rejected the proposal, and therefore TNUoS tariffs will continue to be set with 2 months' notice. The discussion held by the workgroup is therefore irrelevant. The discussions and writing of this report took place prior to the publication of a letter by Ofgem on the charging arrangements for Embedded generation. The content of the letter have not been discussed by the Workgroup.

Disapplication Date

3.3.20 The aim of including a disapplication date in the Original proposal was to emphasise that the purpose of the modification was to address the potential damage to competition during the period of Ofgem's consideration (and possible review) of electricity charging arrangements; to stress the temporary nature of the modification; and to make clear that in no way was the modification attempting to pre-judge the outcome of Ofgem's work.

3.3.21 If Ofgem's consideration this summer were to lead to a conclusion that no changes are needed to charging in the CUSC, it is likely that CMP 264 would not be approved. Conversely, if Ofgem does decide that changes are likely to be needed the next step is likely to be a review of electricity charging arrangements (most likely a Significant Code Review (SCR) process) culminating with Ofgem raising CUSC modifications or directing National Grid or another CUSC Party to raise CUSC modifications to implement the conclusions of the review. On implementation of such CUSC modifications, the existing CUSC baseline including CMP264, if approved, would be changed.

3.3.22 It is therefore clear that whether CMP264 contains a Disapplication Date or not, should it be implemented, its provisions will either:

(a) Continue in force should the Authority conclude that the baseline including CMP264 is the most efficient outcome; or

(b) Be replaced by provisions introduced into the CUSC modification process by Ofgem on the conclusion of its review.

3.3.23 While the Proposer considers that CMP264 is greatly superior to the current baseline, it considers that it is likely that the latter scenario is the more probable outcome.

3.3.24 In any event, it is not possible, at present, for the Workgroup to know the timing or the outcome of Ofgem's review and how any recommended changes will be implemented. This could present problems in defining a Disapplication Date in terms of a specified action by the Authority in the CUSC legal text.

3.3.25 The alternative, of defining a firm Disapplication Date, is also problematic as the timetable for Ofgem's review and the modification process which could potentially follow is uncertain. Too short a Disapplication Date could lead to a hiatus between the disapplication of CMP264 and the implementation of Ofgem's conclusions. Too long a Disapplication Date (e.g. 2026) leaves the provisions subject to the normal modification process and would be in effect meaningless.

3.3.26 It has to be recognised that the use of a firm Disapplication Date can in no way bind Ofgem or the Authority to a date for concluding the review and implementation the conclusions.

3.3.27 On this basis, while continuing to emphasise the intended temporary nature of CMP264, the Proposer has concluded that formal provisions for a Disapplication Date would add little in practice to the proposed Modification. Accordingly, it has decided not to include Disapplication Date provisions in the Original proposal.

Does the Original Proposal apply to SVA or CVA embedded plant

3.3.28 The proposer has identified that certain embedded generators are able to secure payment of Triad avoidance benefits either directly or via another BSC Party through registering their embedded plant as an Embedded Exempt Export BM Unit in Central Volume Allocation (CVA). Metering data for these BM Units is currently made available to National Grid for TNUoS payment purposes. It is proposed that new embedded generation as per the modification definition that registers as an Embedded Exempt Export BM Unit after the cut-off date should be classified as New embedded generation and that no payment of TNUoS is made to Embedded Exempt Export BM Units which export over the Triad periods. (this is not intended to discriminate existing embedded generation commissioned prior to the cut-off date from subsequently re-registering as an Embedded Exempt Export BM Unit).

3.3.29 One workgroup member noted that the mechanics of this approach could be discriminatory to existing sites (i.e. sites that are not new embedded generation under the definition and that choose (for unrelated reasons) under a BSCP to register/switch from SVA to CVA after the 01 July 2017 could find themselves unable/restricted to enter into other markets or change the meter classification. This could be anti-competitive as it could lock out capacity from entering into certain market arrangements.

3.4 CMP265 specific discussions

3.4.1 The workgroup held various discussions on the particular details of the CMP265 proposal, which are summarised in the following section.

Generators impacted

3.4.2 The proposer confirmed the intention was to impact both SVA and CVA registered embedded generation with a capacity market contract.

Implementation date

3.4.3 The Workgroup were generally content with an implementation date of 1 April 2020, as this gave a reasonable period of time to adjust.

3.4.4 There was discussion related to units which had entered the capacity market in good faith in the 2014 and 2015 auctions expecting to receive embedded benefits, but would now, under the original proposal, would not. There are some alternatives around retaining embedded benefits for existing CM holders in the alternatives section, but the original is still to include all capacity market contract holders regardless of when they secured their Capacity Market Agreement. Some Workgroup members saw this as unjust interference into a 15-year contract arrangement which will only be 18 months old when this change is imposed.

3.4.5 A workgroup member noted that this change might cause capacity to surrender their contracts under earlier auctions, and bid in to a later auction if they think there will be a higher clearing price off the back of embedded benefits being removed. It was noted that this would be a decision for individual units based on the economics involved, the penalty applied to not honouring the original contract, and the risk associated with entering a future auction. Some Workgroup members noted that the value at stake over 15 years does make this a real issue of concern.

Mixed Sites

3.4.6 Mixed sites are those which contain a mixture of demand and embedded generation; and may either be taking energy from the distribution network, taking zero energy (either as there is no demand, or demand is met by onsite generation), or exporting energy on to the distribution network.

3.4.7 The proposer originally intended to only capture pure generating Capacity Market Units (CMUs) and not mixed sites. However, at the first BSC Meeting on P349, the proposer of CMP265 was challenged by other members of the workgroup, over the difficulties of excluding mixed sites where a CMU comprised of embedded generation (CMEG) is part of a site with demand and perhaps other non-CM embedded generation, from the scope of CMP265. Such sites are thought to be rare, although the Workgroup did not review any analysis on the numbers. One BSC workgroup member knew definitely of one such site; there might be more. Some had concerns that even “simple” CMEG on an isolated, CMEG-only site, might add some demand to its site to take it outwith the scope of CMP265. Others had a concern that if the definition of what’s in scope of CMP265 was, instead, defined as sites where the CM meter is the same thing as the BSC-accessible site boundary meter, a “pure” CMEG with no demand on site (which this would be intended to catch/define), might make itself outside the scope of CMP265 by adding a separate CMEG non-BSC-accessible meter in series with its BSC boundary metering.

3.4.8 Therefore, the proposer acceded to the possibility of using a different approach (which would affect the framing of CMP265 Original): to use net BSC-accessible boundary metering for all CMEG (which would all be in scope of CMP265, even in the case of a mixed site with demand or other non-CM embedded generation – but not a DSR CMU involving embedded generation in the DSR CMU that is not, in its own right, in the CM).

3.4.9 It was suggested that plants once built, and receiving payments under existing CM contracts, may choose to simply “tear them up” in future years instead relying on the much greater revenue available from running for Triad Avoidance and thus threatening system security.

3.4.10 To cope with the instance of CM and non-CM embedded generation on the same site, it might be necessary to add this feature:

(a) To avoid penalising the output at time of Triad, where the site is net-exporting, of non-CM embedded generation when running at Triad at such a mixed site : a new requirement via the CUSC on the Supplier to declare if it was able to, to Grid or ELEXON if there is non-CM embedded generation on a (i.e. mixed) site with non-BSC-accessible CMEG…. [*the Supplier could require/encourage its customer to give that data to the Supplier, via its retail contract – but the BSC workgroup considered that the customer would have a commercial incentive to give that data to the Supplier, as it could only gain from doing so*] …. the Supplier would tell Grid the volume allocated to Triad benefit (*to be charged differently under CMP265*) at that site using allocation rules agreed between the customer and Supplier … e.g. if site at Triads was net-exporting 50 MW, and 20 MW of that was from CMEG, the 20 MW from CMEG is declared by the Supplier and loses Triad benefit but not the other 30 MW from other embedded generation. Default, if no such declaration is made by the Supplier, is that all of the net export volume from sites with a CMEG present is assumed to be caught by CMP265. A workgroup member suggested at the BSC Workgroup meeting that the Supplier (working with its customer) might draw up allocation rules in advance and lodge them with Grid for each of the mixed sites (these are expected to be very rare; workgroup members between them knew of one) that has non-CM embedded generation alongside CM embedded generation, to give confidence in the data.

Consultation Question 11: Applies to CMP265 Only

i) Views are sought on the implication for mixed sites discussed in 3.4.10.

ii) Views are sought on the preference of categories of capacity Market CMU captured by this proposal, please indicate your preference from the following list and reasons:

- All existing and new distribution generation CMUs
- All existing and new distribution generation CMUs and DSR CMUs (proven and unproven)
- All price maker CMUs
- All newbuild/prospective distribution generation CMUs only (defined as >1year contracts)

3.5 Impact of the CMP264 Original Proposal

3.5.1 CMP264 Original proposes a distinction of the type of embedded generation on the basis of a distinction of “new” from a date of 30 June 2017, for SVA and CVA registered plant. Therefore, plant considered new after 30 June 2017 would not be eligible for the demand TNUoS embedded benefit. This section investigates the impact in the total value of embedded benefit if the CMP264 Original were to be implemented. Whilst results are shown for the years to 2020, some Workgroup members believe that in the later years an over-riding effect will come from Ofgem’s consideration of the issues (and any review which may ensue).

3.5.2 The total volume of embedded generation predicted to be generating at peak, and therefore eligible for demand TNUoS Embedded benefit is shown in Table 7 under the Baseline; this follow the same National Grid analysis presented earlier using FES 2016 data. Two assumptions are made on the size of an average embedded generation to give an indication of the number of units affected; first a value of 30MW / unit which is the average size of units on the capacity market register[33], and secondly, 12.8MW / unit which is the average size of units on the embedded generation register[34].

		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Installed Capacity	**MW**	18741	21376	23344	24835	25735	26150
Output at Peak	**MW**	7283	7480.4	8030.4	8999.6	9705.4	9878.8
Estimate of Number of Units	**Based on 30MW**	625	713	778	828	858	872
	Based on 12.8MW	1464	1670	1824	1940	2011	2043

Table 7: Capacity and Winter Peak from FES 2016 data (No Progression), with estimated number of Units

3.5.3 Under the CMP264 Original proposal we assume that new-build generators are commissioned on an evenly distributed basis through 2017/18, and therefore three-quarters of them will be ineligible for embedded benefits in 2017/18 as they would be considered “New” – the data is taken from the FES 2016 model and assumes the market outlook as of today.

3.5.4 Several Workgroup members noted that not all this generation would operate / be built under different market condition[35] as the negative impact of CMP264 is considerably higher than the lost deposit from cancelling a CM contract, market participants may decide not to build plants that cannot be commissioned by June 2017. In any case the reduction in indicative embedded benefit due to the CMP264 original as set out in table 8 would still remain the same.

3.5.5 The embedded generators impacted compared to the baseline are shown in Table 8, and the indicative change to the value of the embedded benefit. .

33 https://www.emrdeliverybody.com/CM/CMDocumentLibrary.aspx

34 http://www2.nationalgrid.com/UK/Services/Electricity-connections/Industry-products/Embedded-Generation-Register/

35 Generators may choose to default under the newbuild capacity market obligations putting projects into termination with significant termination fees/costs payable (£25,000/MW plus sunk development, legal and utility costs for each MW impacted and job losses) that could be between £100m-£200m to the detriment of these impacted sites/companies.

		2017/18	2018/19	2019/20	2020/21
Per Year					
Installed Capacity	MW	1156	1556	782	367
Output at Peak	MW	531	1034	585	279
Number of Units	Based on 30MW	39	52	26	12
	Based on 12.8MW	90	122	61	29
Cumulative					
Installed Capacity	MW	1156	2712	3494	3860
Output at Peak	MW	531	1565	2150	2429
Number of Units	Based on 30MW	39	90	116	129
	Based on 12.8MW	90	212	273	302
Percentage of embedded generators		6%	0	0	0
Indicative value of embedded benefit					
Baseline	£m 16/17	374	465	526	650
CMP264 Original	£m 16/17	350	387	412	495
Reduction due to CMP264 Original	£m 16/17	-24	-78	-114	-155

Table 8: Generator captured by CMP264 Original Proposal and therefore not eligible for demand TNUoS embedded benefit.

3.5.6 The value of the embedded benefit under CMP264 Original is shown in Figure 8.

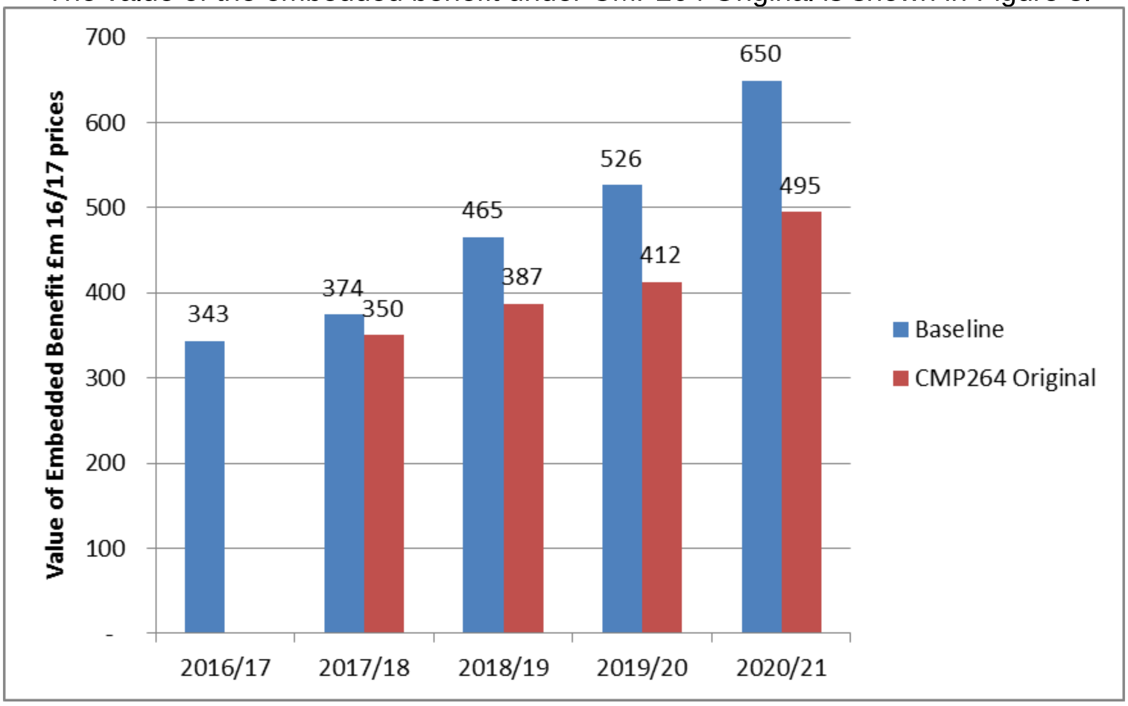


Figure 8: Total value of the TNUoS embedded benefit under baseline and CMP264 Original Proposal

3.6 Impact of the CMP265 Original Proposal

3.6.1 CMP265 Original proposes removal of embedded benefit from 2020/21 onwards for those generators holding a capacity market contract. This section investigates the impact on the total value of embedded benefit if the CMP265 Original were to be implemented.

3.6.2 The underlying other data in this scenarios is consistent with the analysis for CMP264 above, with assumption from the capacity market aligned to section 3.8. In the 2014 auction (for delivery in multi-year contracts from 2018), there was 1GW of new embedded generation. In the 2015 (for delivery in multi-year contracts from 2019) there is 1.1GW of new embedded generation. For the 2016 auction (for delivery in multi-year contracts from 2020), we are forecasting the same 1.1GW in the baseline scenario.

3.6.3 This means that in charging year 2020/21, there is estimated to be a total of 3.2GW of embedded generation on capacity market agreements.

3.6.4 The total value of embedded benefit under the Original and CMP265 Original are shown in Figure 9.

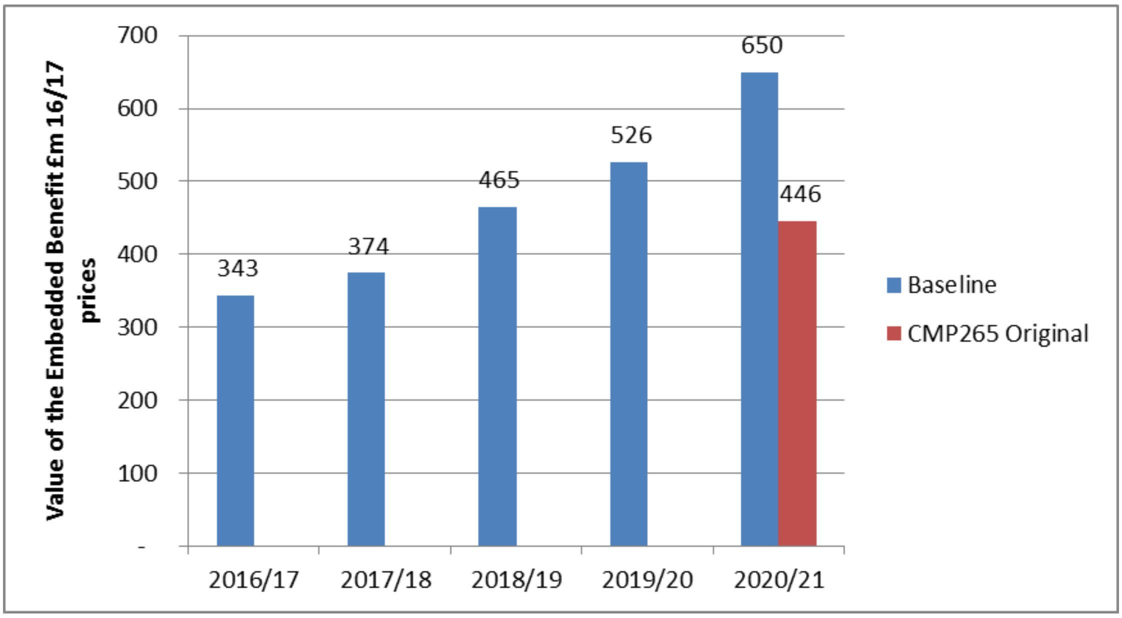


Figure 9: Total value of the TNUoS embedded benefit under baseline and CMP265 Original Proposal

3.7 Note on Technical Implementation – Impact of Gross Charging

3.7.1 At present National Grid sets and recovers demand TNUoS on the basis of net demand. Moving to a different charging base (i.e. gross charging) changes the way in which National Grid forecasts, sets and bills for demand TNUoS.

3.7.2 To consider the potential approach to setting tariffs and money flows under gross charging, the following two approaches are worked through.

New Approach 1 – Gross charging without embedded benefits removed

3.7.3 To account for different treatment of some categories of embedded generation, these categories will need identifying and their volume at Triad understood separately. To this end, the total volume of energy produced by embedded generation needs to be split between those eligible for existing embedded benefit (A) and those who are not (B) in Figure 10. National Grid, in addition to the net demand, would now need to know the energy produced by embedded generation (B) who are not eligible for embedded benefits.

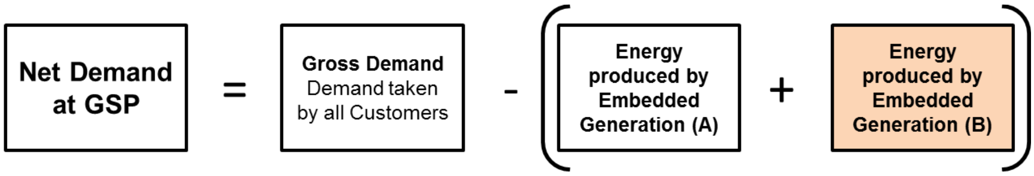


Figure 10: net demand, with two categories of embedded generation

3.7.4 In this context, the charging base for HH tariffs now changes from net demand, to being net demand plus energy put on by embedded generator with zero embedded benefits (B).

3.7.5 As an example consider a system peak of 48GW net demand; however, behind this is 2GW of embedded generator liable for current embedded benefit and 5.5GW liable for the zero rate. As shown in Table 9.

3.7.6 The demand tariff is now £2,000m / (48GW + 5.5GW) = £41.12/kW. This is then charged to a supplier on the basis of the new quantity “net demand + energy from embedded generators without embedded benefits” (N+EG2 in the table).

		System			Suppliers			
			Total		A	B	C	D
net demand	N	GW	48		12	12	12	12
embedded generation (current arrangement)	EG1	GW	2		0	1	1	0
embedded generation (zero rate)	EG2	GW	5.5			0	1	4.5
Demand Residual	RD	£m	2200					
HH Tariff, charged on N+EG2 basis	**DT= RD/(N+EG2)**	**£/kW**	**41.12**					
Supplier TNUoS Bill								
HH Chargeable Volumes	N+ EG2	GW			12	12	13	16.5
Total Bill	DT*(N+EG2)	£m			493.45	493.45	534.57	678.50
Supplier Cost Model								
TNUoS recovered gross					493.45	534.57	575.70	678.50
embedded benefit Paid					0	-41.12	-41.12	0

Table 9. Example with zero embedded benefit for some embedded generators.

3.7.7 In this example, the unit rate for HH demand tariff is reduced as the charging base is now larger. All suppliers still charge their end consumers gross. For Supplier B this recovers an additional £41.12m which is the embedded benefit for the existing 1GW of embedded generation. Supplier D with only new zero rate embedded generation recovers his charges net from his customers, but does not recover anything additional to his TNUoS bill as no embedded benefits are payable.

3.7.8 The precise mechanism of paying embedded benefit to embedded generators would remain a contractual relationship between the supplier and the embedded generator, but now different signals are being provided via the TNUoS Demand tariff.

New Approach 2 – Gross charging with a fixed rate embedded benefit

3.7.9 A further model explored by the workgroup, is the new category of embedded generator which may be paid an embedded benefit not equal to the demand residual, but some other fixed amount. The value of £45/kW is used here for illustrative purposes only.

3.7.10 Table 10 updates the same data from approach 1, to cover this situation. In particular the charging base for the HH tariff is as New Approach 1 being the net demand plus the embedded generation liable at the new rate. However, HH tariffs are now increased to include the additional 'fixed rate' that must be paid to the specific embedded generation.

3.7.11 Importantly, this process brings the allocation of embedded benefits and the redistribution effect into the calculation of TNUoS, without adjusting the total TNUoS value.

		SYSTEM			Suppliers			
			Whole		A	B	C	D
net demand	N	GW	48		12	12	12	12
embedded generation (current arrangement)	EG1	GW	2		0	1	1	0
embedded generation (new rate)	EG2	GW	5.5		0	0	1	4.5
Demand Residual	RD	£m	2200					
HH Tariff, charged on N+EG2 basis	DT= (RD+EG2*EBT) /(N+EG2)	£/kW	45.75					
Benefit tariff for embedded generation (new rate)	EBT	£/kW	45					
Supplier TNUoS Bill								
HH Chargeable Volumes	N+ EG2	GW			12	12	13	16.5
embedded generation (new rate)	EG2	GW			0	0	1	4.5
HH Bill	DT*(N+EG2)	£m			548.97	548.97	594.72	754.84
New embedded generation Credit	-EG2*EBT	£m			0.00	0.00	-45.00	-202.50
	TOTAL NGET BILL	£m			548.97	548.97	549.72	552.34
Supplier Cost Model								
Recovered from gross Volume	(N+EG1+EG2) *DT	£m			548.97	594.72	640.47	754.84
Embedded benefit to EG1 at DT	DT*EG1	£m			0.00	-45.75	-45.75	0.00
Embedded benefit to EG2 at EBT	EBT*EG2				0.00	0.00	-45.00	-202.50

Table 10. Example with a new rate embedded benefit for some generators.

3.7.12 Neither Approach (1) or Approach (2) is particularly more complicated to implement than the other – the exception being that Approach (2) now has two tariffs which must be billed against using different quantities. Both approaches have their complexity in needing to forecast the volume of the embedded generation available for a different rate of embedded generation, and capture them effectively through the aggregated data that National Grid receives from ELEXON.

3.8 Impact on the markets and parties

Embedded generation in the Capacity Market

3.8.2 Further information on the capacity market can be found online[36].

3.8.3 Distribution connected assets have been prominent in both the 2014 and 2015 Capacity Market Auctions.

3.8.4 **2014 Capacity Market Auction.** Of the 49.3GW of de-rated capacity awarded contracts in the 2014 CM auction 4.1GW was awarded to Distribution connected Capacity Market Units (CMU's).

3.8.5 2.6GW of New Build CMUs [multi-year contracts] were successful in winning contracts in the 2014 auction of which 1GW was awarded to Distribution connected CMU's. However whilst the New Build contracts were awarded to 75 separate Distribution CMU's the Transmission connected New Build contracts were awarded to two CMU's from one provider forming one large CCGT plant which, one workgroup members noted, has reportedly been issued with a termination notice for failing to achieve its "Financial Commitment" milestone, as specified under the CM Rules.

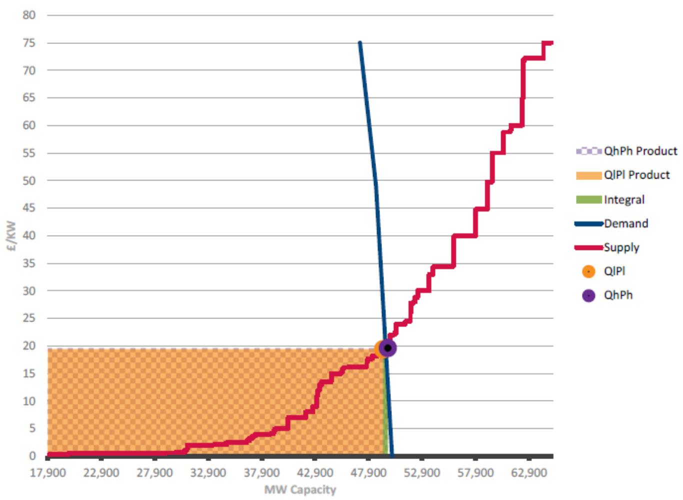
3.8.6 **2015 Capacity Market Auction.** Of the 46.4GW of de-rated capacity awarded contracts in the 2015 CM auction 4.2GW agreements was awarded to Distribution connected Capacity Market Units (CMU's).

3.8.7 1.9GW of New Build CMU's were successful in winning contracts in the 2015 auction of which 1.1GW was awarded to Distribution connected CMU's. New Build contracts were awarded to 72 separate Distribution CMU's. The Transmission connected New Build contracts were awarded to two CMU's from one provider forming one large CCGT plant, Carrington, which was already under construction prior to the 2014 and 2015 auctions.

3.8.8 **Impact on auction clearing prices.** Whilst it is difficult to precisely calculate the impact Distribution connected CMU's have had on the Capacity Market clearing prices it is likely that with new Distribution connected capacity winning 2.1GW of 15 year CM contracts across the two auctions this capacity has increased competition and led to lower auction clearing prices and lower capacity market costs levied on the end consumer for the duration of these agreements through to 2035. Some Workgroup members also highlighted that approximately 5GW of prospective/newbuild transmission generation capacity secured 3-15year capacity market contracts and has so far failed to deliver on their obligations, this too has had significant impact on the capacity market to date and should be considered in the round when discussing impacts of embedded generation participating. One Workgroup member noted that the large volume of existing plant keen to gain contracts and new transmission connected CCGTs prepared to bid at unusually low prices would have also been significant factors in depressing auction prices. Figure 11 are the final auction results supply curves for the 2014 and 2015 T-4 capacity market auctions showing the bid prices v capacity against the final target volume procured.

[36] https://www.gov.uk/government/collections/electricity-market-reform-capacity-market

Final Auction Results T-4 2014 Capacity Market



Final Auction Results T-4 2015 Capacity Market

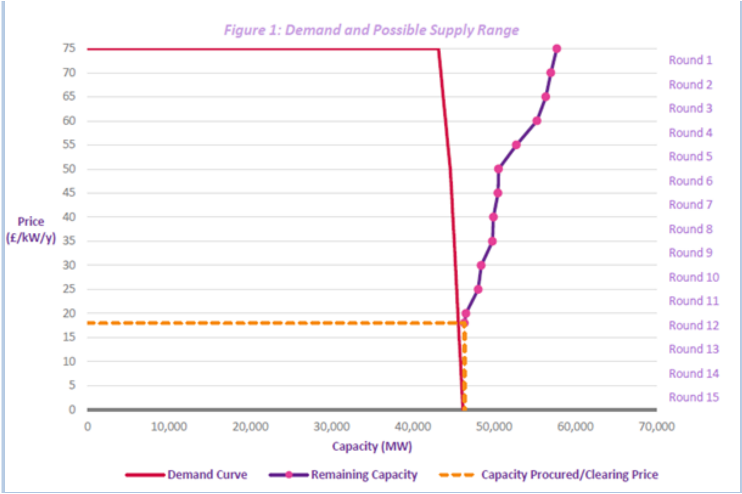


Figure 11: Clearing prices for 2015 and 2014 Capacity Market Auctions

3.8.9 In the 2015 auction 2.3GW of new build distribution connected CMU's were unsuccessful in the auction. It is likely that a significant proportion of this capacity will participate in the 2016 auction and may have an impact on auction clearing prices. One Workgroup member noted that recently the Secretary of State published the Capacity Market Parameters for the up and coming T-4 2016 Capacity Market auction citing a target volume of 52,000MWs to be procured – significantly higher than the expected 47,000MWs based on capacity already procured in the previous two capacity market auction results. The workgroup member also noted that the biggest impact recognised at this stage is the increase in the target capacity to be procured to cover potential failures of the aforementioned 5GW of Transmission connected capacity that has so far failed to meet its Capacity Market obligations/milestones. The impact of procuring this increased capacity is designed to procure more capacity and push up the clearing prices.

3.8.10 DSR participating in the capacity market may or may not include embedded generation, but neither Original proposal introduces changes to DSR tariffs. Some workgroup members have highlighted this represents selective discrimination and create further distortions and inequity within the industry.

3.8.11 CMP265 explicitly raised the issues for impact on the capacity market of the embedded benefit, and CMP264 raised the issue at their presentation at the workgroup. The details of the capacity market are not defined in the CUSC and these modifications cannot change the capacity market. To this end, the workgroup is interested in further view of the impact demand TNUoS Embedded benefit on the capacity market The workgroup are interested in your views on this topic.

Consultation Question 12: Applies to both CMP264 and CMP265

Can you identify – either quantitatively or qualitatively - the impact of the demand TNUoS embedded benefit on your decisions made in making capacity market decisions?

Impact on Suppliers

3.8.12 By charging TNUoS on a gross basis, the tariffs are likely to reduce. This means that some suppliers may see their charges reduce, and other may see their charges increase. Overall, the total value of TNUoS is unchanged. Suppliers will still need to deal with payment of embedded benefits to generators directly and for SVA register suppliers this is not covered under the CUSC but rather under the individual PPAs with embedded generators.

3.8.13 In addition to their existing net demand, suppliers will need to provide forecasts of the amount of embedded generation which receives the new rate of embedded benefit for tariff setting and billing:

(a) CMP264. Suppliers need to apply the definition of "new embedded generation" as determined under the proposal;

(b) CMP265. Suppliers need to capture output from those embedded generators with a capacity market contract.

3.8.14 Particularly under CMP264, where changes would apply for the 2017/18 Triad season, it may be challenging for Suppliers to implement through contracts and billing systems in this time period. The complexity of determining whether a generator is new or existing may add further complications. There is an existing issue here about the incentive on suppliers to provide the right data, but this may complicate the matter further. It was however noted by one Workgroup member that this view may over-state the impact on suppliers. Suppliers already have to cope with a sharply increasing profile of embedded generation which is increasing TNUoS unit rates; the abatement of this growth would arguably increase the stability and predictability of TNUoS charges rather than the converse, Similarly, for the actual embedded generation Triad avoidance payments, only new embedded generation will be captured for CMP264, and therefore any impact on payment arrangements will be limited (and it may be that simple work around solutions can employed).

Consultation Question 13: Applies to CMP264 Only

Do you have a view of whether implementation for the 2017/18 Triad season is sufficient to allow changes for i) supplier contracts and billing system, and ii) for other stakeholders?

Consultation Question 14: Applies to CMP265 Only

Do you have a view of whether implementation for the 2020/21 Triad season is sufficient to allow changes for i) supplier contracts and billing system, and ii) for other stakeholders?

Impact on generators

3.8.15 **CMP264** – New Embedded Generators would receive no embedded benefit compared to generators who are considered existing who will continue to receive the embedded benefits as currently defined. This will affect the build decisions for embedded plant and the decision to run or not over the Triad periods. It means that there would be two categories of embedded generators (those with and those without the Triad embedded benefits) participating in the same market.

3.8.16 Without embedded benefit, this may affect the economics of deciding about new and existing plant at transmission level, and is expected to have a direct impact on the capacity market for 2016, causing an increase in prices.

3.8.17 **CMP265 –** all generation not on mixed sites with capacity market contract would not receive demand TNUoS embedded benefit. This places all capacity market generation in the same category, except those who won multi-year contracts in 2014 or 2015 on the basis of embedded benefits being part of the regime at the time of the auction, placing these early entrants at a disadvantage. Capacity Market embedded generators will also be participating in the same wholesale market as those generators who still receive embedded benefits. Embedded generators may decide not to enter the capacity market in order to continue to be eligible for the TNUOS Triad benefit. This would require adjustments to the capacity market demand curve.

3.8.18 Without embedded benefit, this may affect the economics of deciding about new and existing plant at transmission vs. distribution level, and is expected to have a direct impact on the capacity market for 2016, causing an increase in prices.

Impact on the BSC - ELEXON

3.8.19 CMP264 and CMP 265 both propose to remove TNUoS embedded benefits for some (but not all) sites with embedded generation. Consequently the overall impacts on the BSC are similar too. That is, in each case National Grid requires gross export data for relevant exporting MSIDs or BM Units, which they will add back into the TNUOS chargeable demand of relevant Suppliers. The main differences are:

(a) Which generators are within scope, i.e. New Embedded Generators for CMP264 and generators with Capacity Market contracts for CMP265; and

(b) The Implementation Date, i.e. a CMP264 solution needs to be in place for the 2017/18 Triad, whereas a CMP265 solution will not be needed until the 2020/21 Triad.

3.8.20 In order to facilitate the implementation of CMP264, Scottish Power raised BSC Modification Proposal P349. To facilitate the implementation of CMP265, EDF Energy raised P348. The BSC Panel considered both Modification Proposals on 4 July 2016 and recommended that ELEXON develop both proposals according to an urgent timetable. However, the Authority concluded that both modification proposals should not be treated as urgent.

3.8.21 Both P348 and P349 are similar in their overall intent and so share similar challenges in order to deliver a solution. These can be characterised as i) being clear how to identify the correct MSIDs to report and ii) defining a method for collecting, aggregating and reporting metered data to National Grid.

3.8.22 SP's P349 Modification Proposal Form proposed that Half Hourly (HH) Data Aggregators (DA) should provide gross metered data directly to National Grid in the most efficient and cost-effective process, similar to the processes already used to send metered data to the EMR Settlements Company.

3.8.23 EDF Energy's Modification Proposal Form for P348 proposed that ELEXON report details of gross metered data (import and export) to National Grid by including this data in the TUOS Report (P0210).

3.8.24 In practice National Grid may require metered data from different types of embedded generator to facilitate both CMP264 and 265. That is, National Grid may require metered data from Metering Systems registered

(a) In the Central Meter Registration Service (CMRS) as part of a Balancing Mechanism Unit (BMU),

(b) In the Supplier Meter Registration Service (SMRS) that ultimately contribute to Supplier BMU volumes; and

(c) For Capacity Market purposes only, i.e. outside CMRS or SMRS.

3.8.25 National Grid already receives specific metered data for BMU embedded generators registered in CMRS. Therefore we don't envisage any impact on the BSC in respect of this existing provision of data.

3.8.26 ELEXON also sends National Grid a daily TUOS Report (P0210) containing a breakdown of each registered Supplier BMU's 'Period BMU HH Allocated Volume' and 'Period BMU NHH Allocated Volume' in each GSP Group and for each Settlement Period. However this report provides a net half-hourly (HH) and non-half-hourly (NHH) volume of all demand and generation registered under a Supplier BMU. In order to suspend the payment of embedded benefits for the generators that CMP264 and 265 are concerned with, National Grid requires gross export metered data for these generators so it can add this back to the net volumes already reported in the P0210.

3.8.27 ELEXON and Suppliers do not currently have permission to report metered data for non-BSC Settlement metering systems (i.e. meters used by CM providers for CM purposes only, which are not registered in SMRS or CMRS). Access to metered data from these metering systems would require changes to the Capacity Market Rules. A change to the CM Rules would be required to facilitate the provision of metered data for non-Settlement metering systems used for reporting CM Generators. Any proposal to change the CM Rules would need to comply with the processes and CM Objectives set out in the Regulations. Ofgem is responsible for administering the change process to the CM Rules and has published guidance on its website entitled 'Guidance for the Change Process for the Capacity Market Rules'. Our understanding is that Ofgem considers proposals to change the CM Rules on an annual basis unless the proposal is considered urgent. As such reporting metered data from these metering systems is outside the scope of P348 and P349.

3.8.28 Therefore, ELEXON's understanding is that both P348 and P349 intend to facilitate the provision of export metered data from Metering Systems registered in SMRS only.

3.8.29 Whilst both BSC Modification Proposals describe particular methods for reporting gross metered data to National Grid, there may be different ways of achieving the same outcome. For example, both proposals already suggest different methods of identifying and reporting MSIDs for relevant embedded generators. In supporting the proposers drafting of their initial Modification Proposals for P348 and P349, ELEXON shared other ideas too.

3.8.30 ELEXON hosted the first joint Workgroup meeting for P348 and P349 on 12 July 2016. The P348/349 Workgroup considered a variety of options and has decided to develop two broad options for enabling the reporting of gross export metered data:

(a) a more detailed set of BSC requirements and processes that describe specifically how Suppliers, their Party Agents and the SVAA collaborate to collect, aggregate and report data to National Grid (e.g. using the existing TUOS Report); and

(b) a more straightforward set of BSC requirements that simply require Suppliers to provide metered data for individual Metering Systems to National Grid – this second option provides the Supplier flexibility to decide how to report but places greater pressure on National Grid to aggregate the metered data from individual Metering Systems for its purposes.

Consultation Question 15: Applies to CMP264 and CMP265

i) What are your views on the 2 broad options to enable the reporting of gross export metered data?

ii) Would you have the data available required for Option B (both CMP264 and CMP265) for both new contracts and existing contracts where a customer may be partially exempt?

iii) Do you believe you can implement the proposed changes by the respective implementation dates?

iv) What are the pros and cons of the 2 proposals that ELEXON are considering to implement this (P348 for CMP265/ P349 for CMP264)?

3.8.31 Based on option 'a', we envisage that changes may be required to:

- BSC Sections S, V and X;
- BSCPs relating to HH Data Collection and Data Aggregation and Supplier Volume Allocation;
- SVA Data Catalogue – i.e. to modify the P0210 TUOS Report;
- Data Transfer Catalogue – either to define new flows or modify existing ones (i.e. to enable the sharing of individual and aggregated metered data between Party Agents and the SVAA) (e.g. either mimic or modify the D0036, D0040); and
- BSC System, Party and Party Agent system changes – e.g. changes to SVAA, Supplier's, HHDCs, HHDAs and National Grid's systems/software to send, receive and process instructions and metered data.

3.8.32 Option 'b' above may only require changes to BSC Sections as the onus would be on Suppliers and National Grid to determine how to collect, report and aggregate the metered data for Transmission Charging purposes.

3.8.33 It is clear that whichever option is preferred, it is important to be explicit about which metering systems Suppliers should report and how the metered data for these metering systems should be collected, netted[37] and adjusted to include Line Losses and any necessary GSP Group Correction[38].

[37] Where the import and export volumes at an embedded generator site are metered separately, the working group considered a case for netting any on-site import metered data from the on-site export metered data. This is to ensure that the export metered data reported to NG does not overstate the actual exported volumes onto the Distribution and potentially the Transmission Systems.

[38] Adjustments for Line Losses and Group Correction are likely to be necessary to ensure the volumes reported by P348 and P349 are comparable with the volumes already reported in the TUOS Report.

3.8.34 In addition, and depending on the preferred approach to reporting, CMP264/265 and P348/349 Workgroup members will need to give thought to where requirements and definitions are included, whether in the BSC, CUSC or both. For example the destination of primary and enabling requirements.

3.8.35 Each option for collecting, aggregating and reporting metered data to NG has different impacts on the BSC, BSC Systems, Suppliers and Supplier Agents, and therefore has different overall costs and benefits. ELEXON plans to consult on the two broad options described above in parallel with this CMP264/265 consultation. Until the P348/349 consultation and Impact Assessment are completed it is unclear what the impacts of CMP264 and 265 might be for the BSC, BSC Systems, Suppliers and Supplier Agents.

Impact on Tariff Setting and Forecasting - National Grid

3.8.36 In order to implement either of these modifications, as identified in the section about implementation approaches, National Grid needs to set and bill tariffs on the basis of new information that it currently does not receive from ELEXON. National Grid's systems and processes will need to be updated to reflect any changes agreed.

3.8.37 **Initial changes.** Changes will be required to the transport and tariff model, to calculate the tariffs on a zonal basis using the new demand charging base within each zone, and associated consequential changes.

3.8.38 Changes will be required to National Grid's billing system (CAB) to receive the updated data from ELEXON, and to bill against the new demand quantity. This is an easier task if there is only one tariff to billed against (i.e. embedded generation receives a zero in total tariffs). If it receives either a value of the residual and/or the locational this will require more complex changes to introduce a different charging quantity and tariffs to bill against.

3.8.39 **Enduring change**. The main enduring changes are that National Grid will now need to forecast the volume of embedded generation which is not liable for embedded benefit separately from net demand at Triad, in order to set the correct charges. This introduces further risk to National Grid in determining the forecasts, particularly when we do not have particularly good data about embedded generation.

3.8.40 Also on an enduring basis the billing of customers is slightly more complicated if there are additional tariffs to bill against.

3.8.41 Having an additional quantity to forecast, may increase the forecasting risk, however, any over or under-recovery in TNUoS due is carried forward to year + 2, in the "K" factor as defined in National Grid Licence (Special Condition 3A.16)

3.8.42 **Thoughts on manual Workaround as a temporary solution.** It was proposed by the Workgroup that manual workaround for data could be implemented in the short term, particular for CMP264, whilst new data streams were established via ELEXON.

3.8.43 The National Grid billing system is built to deal with aggregated demand for BMU's at a GSP; it does not deal with data at MPAN level. In the past, National Grid has and can manually amended the demand data which then feeds into HH and NHH for a BMU which is what we have done for CMP241, which was raised as an urgent modification.

3.8.44 The temporary solution was intended for a year, but has been extended.

3.8.45 From a National Grid' internal audit perspective this is not acceptable but for a one off solution lasting a year it was deemed passable. For CMP264, it may be possible to operate a manual workaround for the first year, if reliable data could be obtained to bill against, given the relatively small number of units forecast to be captured in the first year.

Consumer Impact of CMP264 and 265 Original Proposal

3.8.46 Overall, there were differing views of the workgroup members on whether there was a positive or negative consumer benefit depending on their views of the cost reflectivity of charges and the secondary impacts, i.e. on the power and capacity markets. There was more consensus around the short-term impacts, and less around longer-term impacts. Whether the long run benefits of cost reflectivity (to the extent that charges are not already cost reflective) and effective competition are likely to outweigh the expected short run increase in CM clearing prices resulting from embedded generation having to bid higher in future CM auctions is not determined.

3.8.47 The consumer impacts are likely to result in short term and longer term changes. However, the timescales of this modification did not allow for detailed modelling of consumer impact through a 'full market model'. However, during the Workgroup one Workgroup member highlighted the general principle that if price signals are cost reflective, then the decisions which users make in response to those price signals will be aligned with the interest of society.

3.8.48 **Power market prices.** A number of embedded generators are considered to be flexible generators i.e. they are specifically designed to meet peak demand in the short term. Should these plants no longer be able to operate in this way due to a change in their economic circumstances or they are no longer incentivised to generate at peak this is likely to increase peak power prices.

3.8.49 **Security of supply** There is also the potential issue of security of supply, whereby embedded plant that has been contracted by the CM (or NG) may no longer be economically viable to proceed. This risk may possibly be offset by the potential for the early CM auction to contract sufficient supply, or by a sufficiently "soft landing" for imposing any changes to embedded benefits so that the impact is not felt in the coming winter. One Workgroup member also considered that the continued closure of transmission connected generation due the market distortion caused in part by the high level of embedded benefits would have a greater Security of Supply implication than that of the failure to build a quantity of embedded generation due to the removal of all or most of the TNUoS embedded benefit.

3.8.50 The proposer notes that the potential impact from CMP264 on generators holding existing CM contracts is reduced as it only applies to embedded generators commissioning after 30 June 2017.

3.8.51 Some workgroup members noted the potential growth in embedded generation outputting at Triad is largely down to the willingness of smaller power companies to invest in new plant under the Capacity Mechanism and these will have anticipated Triad benefit in the business case for investment.

3.8.52 Some members of the Workgroup noted that any changes to incentives at Triad would need time to implement to ensure that security of supply was maintained and some workgroup members noted in particular investment decisions already taken that reach financial close for new build embedded generation should be considered. Some Workgroup members noted that the incentive should be in the energy price, and therefore plant and demand would dispatch to match each other at an appropriate price, others disagreed as this is not the only consideration and distribution connection costs and distribution network charges need to be recovered and this will not be reflected in the energy price alone.

3.8.53 **TNUoS.** In the short term there is likely to be no significant effect on the TNUoS allowable revenue as this is stable over a price control. In the medium and long term the required size of the transmission system will determine the level of TO investment required and ultimately cost to the consumer. Some workgroup members noted that in the absence of sufficiently robust locational signals, a higher level of embedded generation in certain areas causes additional transmission investment. Others Workgroup members disagreed and argued that embedded generation reduces net demand on the transmission network, and balancing demand and generation on distribution networks at all times reduces the need for bulk power transmission, reducing long-term transmission network costs which will be realised in future price controls. The longer term impact is hard to quantify as the demand and generation TNUoS charges are intrinsically linked and driven by investment in both the generation mix, where it connects (onshore v offshore, transmission v distribution) and the resulting network investment requirements.

3.8.54 **Capacity Market Prices.** In the short term there is likely to be an increase in the cleared price of future capacity auctions driven by the removal of the embedded benefit from a number of market participants. The medium to longer term impact is dependent upon many factors that are difficult to ascertain given the pace of change and transition in both the energy mix and the demand profile. One view expressed was in the medium and long-term that it is possible that cleared auction prices could be lower than they would otherwise be driven by increased volume of supply as a consequence of the closures of fewer transmission connected power stations than would otherwise be the case, though this could also be offset by the closure of distribution connected generation assets. Another view is that the removal of the embedded benefit will reduce the amount distributed generation, increase peak net demand and require additional peak capacity procurement than expected, keeping capacity market auction prices higher than the counterfactual over the medium and longer term period. One modelling analysis (Cornwall Energy Review of Embedded Generation Benefits Report for the Association for Decentralised Energy) found that removing the embedded benefit would increase the Capacity Market price but would not result in any additional transmission assets clearing the 2016 Capacity Market auction.

3.8.55 Some workgroup members noted that actions by transmission connected generators such as Trafford Power, Cottam and West Burton have potentially had a significant impact on other transmission connected generators by distorting the capacity market auctions by securing capacity obligations but failing on their commitments. The capacity of these 3 transmission connected sites alone accounts for almost 5GW (10%) of the capacity market. However, not all workgroup members agreed with this interpretation noting that for Cottam and West Burton by taking a multi-year agreement did not distort the outcome of the first auction: the auction would have cleared at exactly the same price if they had taken the one year agreements that they now have.

3.8.56 **Reduced customer cost of embedded benefits** – If demand TNUoS charges were applied on a gross basis, then this would increase the TNUoS demand charging base and correspondingly reduce the published TNUoS demand tariff unit rate. Some Workgroup members took the view that suppliers would pass through to customers the lower published TNUoS tariff which would result in a substantially reduced cost to customers of TNUoS charges. This reduction in cost to customers would occur because the value of embedded benefits paid by suppliers to generators would be reduced, so suppliers would no longer need to recover as much money from customers in order to pay for the embedded benefit. Other Workgroup members took the view that suppliers already charge customers a discount to the published TNUoS tariff by absorbing some of the cost of TNUoS charges and embedded benefits on their own balance sheet, so the resulting reduction in cost to customers may not be as large. National Grid forecasts show the potential value of this reduction in cost to customers compared with the existing arrangements may become substantially greater over time as illustrated in Figure 8 and Figure 9

3.8.57 On balance, in the absence of significant quantitative analysis, it is not possible to definitely state whether the consumer will be better or worse off as a result of these proposals.

Consultation Question 16: Applies to both CMP264 and CMP265

Do you have any further evidence / comments on the consumer impact of changing the demand TNUoS embedded benefit in either the short-run or long-run?

3.9 Variables in potential alternatives

3.9.1 The are several variables which changes could be made to the methodologies based on the categories that have already been discussed. In Table 1 the comparison of the CMP264 and CMP265 Original Proposals were considered.

(a) **Affected embedded generation.** There are different methods for determining which embedded generators receive a different treatment for embedded benefits; these include:

- (i) All generators
- (ii) New embedded generation after a certain date (CMP264 Original)
- (iii) Generators holding a Capacity Market Contract (CMP265 Original)
- (iv) Generators holding an existing Contract for Difference or a Capacity Market Contract

(b) **Value of the embedded benefit.** The new value of the embedded benefit for affected embedded generation could take several values

- (i) Zero (no residual or locational tariff) (CMP264 Original)
- (ii) Locational tariff only (CMP265 Original)
- (iii) A new value of the residual, to be determined
- (iv) A frozen value of, say, the 2016/17 value.

(c) **Implementation Dates.** Changes tend to be made at the start of a charging year (1 April), to apply throughout that year.

Affected embedded generation

3.9.2 Many different options were considered regarding what criteria should be used to define whether or not the relevant tariff element would be applied to demand on a gross or net basis:

(a) **All Embedded generators** – Within this methodology, all embedded generators would be treated the same, therefore this would avoid creating a new defect of discrimination. If the Demand Residual was charged to customers on an entirely gross basis, then no embedded generation could be used by suppliers to offset their liability for that tariff element. However, this solution does not address the part of the proposed defect that embedded generation behind a demand meter would continue to benefit from the economic value of investment and dispatch to avoid the full demand Triad charge as if it remained charged on a net basis.

(b) **New Embedded Generators –** This is the proposal in the Original of CMP264 which suggests that generation from New Embedded Generators should be applied on a gross basis, so they would not provide an embedded benefit to suppliers. By contrast, generation from existing embedded generators will continue to be treated on a net basis, so they will continue to provide an embedded benefit to suppliers. Some workgroup members noted that this causes discrimination between different categories of embedded generation, but other workgroup members noted that it addresses issues for existing generators which were built, financed and tendered into the CM under the current embedded benefit arrangements.

(c) **Embedded generators with a capacity contract –** This is the proposal in the Original CMP265 which suggests that generators should not be able to benefit from both a capacity contract and Triad avoidance at the same time. Some workgroup members noted that this causes discrimination between different categories of embedded generation, but treats all capacity market parties the same, but other workgroup members noted that it affected for generators with existing agreements which were gained through an auction with the expectation of the current embedded benefit arrangements.

(d) **Embedded generators with an existing Capacity, or CfD contract –** This was suggested as a possible alternative. Some workgroup members noted that this causes discrimination between different categories of embedded generation, and also treats some capacity market parties different but other workgroup members noted that it addresses issues for generators with existing agreements which were gained through an auction with the expectation of the current embedded benefit arrangements, by protecting benefits.

Value of the embedded benefit

3.9.3 The workgroup discussed many possible options regarding potential improvements to the way the Demand Residual is charged.

3.9.4 **Gross versus net charging.** The current methodology uses net charging of the whole Triad charge. Therefore embedded generators and DSR face a Triad investment and dispatch price signal which is determined by the negative of the Triad demand charge. This price signal is much more extreme than the TNUoS price signal faced by a Transmission connected generator who's generation can not be used to net-off against supplier TNUoS demand charges, therefore transmission connected generators do not benefit from the value of the avoidance of the demand Triad charge.

3.9.5 Several options were discussed regarding how the treatment of embedded generation could be improved with regard to whether suppliers should be able to net off energy from embedded generation from part or all of their Triad liability:

(a) **Gross charging of Demand Residual –** The proposer of CMP265 specified that only the Demand Residual tariff element should be charged to demand on a gross basis.

(b) **Gross charging of the entire Triad charge** - The Original CMP264 proposal specified that the entire Triad tariff should be charged on a gross basis due to the greater simplicity of the approach. However the proposer considered gross charging on only the Demand Residual tariff element as a reasonable alternative.

3.9.6 **A fixed value of the residual.** This was suggested an a possible alternative which would result in a portion of the Demand Residual remaining charged net, while the remainder of the Residual would be charged gross. This would effectively cap the value of the embedded benefit. The proposal suggested that the level this should be capped at is the current level of the Demand Residual for charging year 2016/17. This approach has drawbacks including:

(a) It is may not be cost reflective because the continued value of the embedded benefit does may not reflect the cost to the transmission either caused, or avoided by the embedded generator receiving the benefit.

(b) It may not address the discrimination defect identified by some workgroup members (not all) between embedded generation and transmission connected generation since generators which may be alike with regard to the cost they cause to the transmission network, will continue to be treated differently with regard to the TNUoS charges or benefits which they face. It should be noted that fully addressing this potential issue is out of scope of this process.

Other parties disagree that this can be considered a defect when there are so many other unaddressed pricing differences between transmission connected assets and distributed connected assets. If the purpose of this modification was expressly to address the differences between different levels of connection then it should not focus on solely removing the argued benefits of only one side of the equation.

(c) The choice of the level at which the net proportion of the Residual should be fixed at is arbitrary, as are the proposed values under CMP264 and CMP265. It would be vital to provide evidence regarding what an appropriate cost reflective value of this may be, which may include a value of zero. Some Workgroup members noted, that there are values for embedded benefits in external publications which are higher than the zero proposed.

(d) It fails to correct the proposed defect with regard to competition for new investment or closure decisions and dispatch decisions for all embedded generation which also fails to address the defect with regard to competition in the capacity mechanism. This is because all embedded generation will continue to make investment and dispatch decisions based on a non-cost reflective price signal.

Other Topics

3.9.7 The Workgroup also briefly discussed other options for charging demand TNUoS charges, such as increasing the strength of the locational tariff, or charging over a different charging base (e.g. a fixed per meter charge, or a change to Triads). No significant further discussion was held on these topics or detailed proposal prepared, however views from industry parties will be useful to inform future discussion if they feel it is in scope of the workgroups discussions.

Consultation Question 17: Applies to both CMP264 and CMP265

Do you feel that both the locational and residual component of the demand TNUoS should be removed as an embedded benefit (as CMP264 Original) or just the residual component (as CMP265 Original) or some other method?

4 Discussions of Alternatives

4.1 Introduction

4.1.1 The workgroup are interested in the view of industry participants to inform the definition of potential alternatives. In additional at this stage a total of 5 alternative proposals[39] have been structured by Workgroup members.

4.1.2 Two of these, both raised by Centrica, are applicable to both CMP264 and CMP265. These are known as Centrica (1) and Centrica (2). Two are applicable to CMP264 only (Green Frog et al, and UPKR 1), and one is applicable to CMP265 only (UKPR 2).

4.1.3 These proposals are summarised in Table 11 overleaf, and for comparison can be compared to the Original proposal in Table 1 on page 7. Further detail on each alternative is then provided based on text provided by the proposers. These proposed potential alternatives were not debated by the Workgroup as the detailed proposals were submitted outside of the meetings.

[39] The only becomes Workgroup Alternative CUSC Modifications during the latter part of the Workgroup Process, and requires a vote by Workgroup members. At present these options may or may not be presented by their proposers as WACMs, and may or may not become WACMs.

	Applicable to Both CMP264 and CMP265		CMP264		CMP265
Short hand Name	**Centrica 1**	**Centrica 2**	**Green Frog et al**	**UKPR 1**	**UKPR 2**
Proposer	Centrica		CUSC Party Viridis 178 Ltd (Green Frog Power) on behalf of: Welsh Power Ltd , PeakGen Ltd, Power Balancing Services Ltd, Alkane Ltd, Hartree Partners Power Gas Company (UK) Ltd, and The Association for Decentralised Energy	UK Power Reserve	UK Power Reserve
Demand TNUoS Embedded benefit for the affected generators	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, but zero residual.	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, and an additional value of £X/kW (to be determined)	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, and an additional value of the 2016/17 Demand Residual (£45.33/kW) increased by RPI for future years.	New Embedded Generators would receive zero embedded benefit (neither the locational nor the residual)	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, but zero residual.
Affected Embedded Generators who have a different value of the embedded benefit	All embedded generators and export from mixed sites.		All embedded generation	All new embedded generation after 30 June 2017, except if it has a CM or CFD contract achieved in the 2014 and 2015 auctions which can still commission after the 30 June 2017 and not be impacted by this proposal.	All embedded generators with a capacity market contract, from 2014 or 2015 Capacity Auctions and those with a CFD agreement after 1st April 2016
Implementation Date	1 April 2020		1 April 2017	1 April 2017	1 April 2020

Table 11: Comparison of the potential alternatives discussed to date

Applicable to both CMP264 and CMP265: Centrica 1 and Centrica 2

	Centrica (1)	Centrica (2)
Proposer	Centrica	
Demand TNUoS Embedded benefit for the affected generators	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, but zero residual.	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, and an additional value of £X/kW (to be determined)
Affected Embedded Generators who have a different value of the embedded benefit	All embedded generators and export from mixed sites.	
Implementation Date	1 April 2020	

Table 12: Summary of Centrica's two potential alternative proposals for CMP264/CMP265

4.1.4 The Proposer of this alternative considers that treating (exemptible) embedded generation exports as "negative demand" for TNUoS charging purposes is not cost reflective and gives undue competitive advantage over transmission connected generation[40]. This distorts competition in the Capacity Market (CM) and other markets embedded generation interacts with.

4.1.5 The Proposer's view an undue competitive advantage to embedded generation exports arises from the effective receipt of the demand residual TNUoS charge[41], which is worth materially more than the generation residual TNUoS charge[42].

4.1.6 From a cost reflectivity perspective, there is no reason to treat a TRIAD export from one embedded generator differently from another embedded generator in the same location on account of them being "new" or "existing" (CMP 264) or whether they participate in the CM (CMP 265). Centrica therefore propose that reforms to the demand TNUoS residual should apply to all TRIAD exports from (exemptible) embedded generation, not simply those that are "new" or participating in the CM. In our view, the specific distortions to investment decisions and competition in the CM highlighted by CMP 264 and CMP 265 would be at least as well addressed by broadening the scope of reform to all TRIAD exports. Benefits to cost reflectivity and competition would be greater.

4.1.7 On the substance of what the TRIAD export tariff for (exemptible) embedded generation should be, Centrica believe two options merit consideration:

(a) Remove the demand residual TNUoS credit from (exemptible) embedded generation exports altogether, such that the credit (or charge) applied for exporting over a TRIAD reflects the locational (marginal) element of demand TNUoS only.

(b) Apply a "locational + x" TRIAD export tariff to (exemptible) embedded generation exports, where "x" equals the generation residual TNUoS charge.

[40] and licensable embedded generation
[41] Or a proportion thereof in accordance with commercial arrangements
[42] The generation residual TNUoS charge has historically represented a significant cost to affected generators. However, National Grid forecast that from 2017/18, the generational residual TNUoS charge will represent a credit (~ £2/KW in 2017/18, rising in subsequent years).

4.1.8 The rationale for option (b) is the generation TNUoS residual could diverge from zero in future years. If this transpires, there could once again be a situation where (exemptible) embedded and transmission connected generation having the same effect on the transmission network would face materially different tariffs, distorting competition.

4.1.9 On balance, Centrica believe effective competition between transmission and (exemptible) embedded generation is most likely to endure under option (b), as residuals would remain equivalent over time. However, Centrica welcome views on options (a) and (b).

4.1.10 For the avoidance of doubt, Centrica propose no changes to who National Grid bills for demand TNUoS purposes versus the current arrangements - only the calculation of the bills would change.

4.1.11 In recognition of the significance of this change and, to some extent, interactions with t-4 Capacity Market bidding, Centrica are sympathetic to the concept of delayed implementation. The proposed CMP 265 implementation date of April 2020 seems reasonable. However, it is the view of another Workgroup member that the value of Triad avoidance that can realised between now and 2020 would continue to significantly distort competition in the next capacity market auction.

Applicable to CMP264: Green Frog et al

	Green Frog et al
Proposer	CUSC Party Viridis 178 Ltd (Green Frog Power) on behalf of: • Welsh Power Ltd • PeakGen Ltd • Power Balancing Services Ltd • Alkane Ltd • Hartree Partners Power & Gas Company (UK) Ltd • The Association for Decentralised Energy
Demand TNUoS Embedded benefit for the affected generators	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, and an additional value capped at the 2016/17 Demand Residual (£45.33/kW) increased by RPI for future years.
Affected Embedded Generators who have a different value of the embedded benefit	All
Implementation Date	1 April 2017

Table 13: Summary of Green Frog et al's potential alternative proposal for CMP264

4.2 The alternative proposal is simple and directly addresses the Original proposer's defect. It treats all embedded plant equally. It avoids a cliff-edge date at which, without robust justification, some plants are treated differently from others. The value of embedded 'benefits' would be frozen at the same level for all plant, regardless of commissioning dates. One Workgroup member has indicated that an earlier implementation date of the following 1st April after an Ofgem decision or any other such date as Ofgem may choose may be appropriate and would put forward an alternative on this basis.

4.2.1 It does require changes to the way that TNUoS charges are calculated, but it would be not be significantly more complicated than the current system nor CMP264. The proposal also has the advantage of treating all export meters the same, making the solution less likely to result in avoidance measures, whereby people change their metering arrangements to avoid being captured by a reduction in embedded 'benefits'.

4.2.2 The alternative aims to better address the defect identified in CMP264 regarding the spiralling embedded benefits and the impacts on competitive behaviour in the Capacity Market. CMP264 envisages non-payment of embedded generators who are commissioned after June 2017. CMP264 further proposes that this proposal will only apply to embedded generators and not behind the meter generation.

4.2.3 The increase in the embedded benefits is not entirely due to an increase in embedded generation, and as such Green Frog et al recognize that the expectation that ever increasing payments to embedded generators has the potential to cause some future market distortions. It is clear also that the Triad levels were considered satisfactory by the market at large in 2014, when National Grid engaged in a thorough review and widely consulted on the matter. Since then, it is not clear that there have been significant changes, other than to the level of the Triad benefit. We therefore propose that a more effective and less discriminatory approach for addressing the defect identified in CMP264 is to cap the residual Triad payment to embedded generators at most the at the 2016/17 level (plus CPI (as current charges)) starting in 1 April 2017 for charging year . The locational tariff would be unaffected by this alternative.

4.2.4 Green Frog et al understand that Ofgem may determine, in the near future, that a thorough review of charging arrangements may be required. Depending on the scope of such a review, if it happens, we share the view of the CMP264 proposer that this could take a significant time to complete, and that an interim, transitional solution might be preferred. Green Frog considers its proposal achieves this aim more effectively that CMP264 because:

(a) it would apply to all embedded generators in the same way, and would be at a level that is closer to a level that the industry found acceptable in the last review.

(b) It would increase with CPI, thereby implying a durability in the event that a "better" solution is not found

(c) It would not have the disastrous impacts on new generation that is potentially unable to meet their capacity market or CfD obligations if they are unable to commission in advance of the cut-off date proposed by CMP264.

(d) The incentive to relocate metering to behind the meter will be reduced, to the extent that the differential to the amount paid to embedded generation and behind the meter generation is smaller than as proposed by CMP264

(e) Directly addressing the spiralling costs and associated market distortions as identified by the proposer of CMP264, where their proposal only addresses the spiralling costs to a minor part of the market (new build embedded generators)

4.2.5 Green Frog et al do not believe, however, that a sufficiently robust case has been made for discriminating against certain types of embedded generation on the basis of whether it is behind the meter or not, or when it has first been commissioned. We suggest that it would be preferable to treat all embedded generators identically.

4.2.6 Green Frog et al's alternative proposal therefore suggests that payments are capped to all embedded generators. Green Frog recognises, however, the practical difficulties associated with identifying embedded generation that sits behind the meter. Therefore, we suggest that our proposal excludes behind the meter generation (as does CMP264), but at the same time we make clear that this is a less than perfect compromise and therefore urge Ofgem to consider whether a Capacity Market rule change or similar may be appropriate to enable an equal and non-discriminatory approach.

4.2.7 At the workgroup discussion there was also discussion around whether the "capped rate" should be some value other than the current £45.33 / kW. One workgroup member noted that in its opinion this alternative did not address the defect, namely the concern that the availability of non-cost reflective payments during the period of Ofgem's expected review could itself significantly distort investment decisions and bidding in the capacity market auctions. Other workgroup members were more content with at the current value than the zero value proposed by the CMP264 Original.

Consultation Question 18: Applies to CMP264 Only

Do you have a view if embedded benefits are frozen at a non-zero value, what should that value be as a £/kW tariff (2016/17 value is £45.33 / kW)?

UK Power Reserve (1)

	UK Power Reserve (1)
Proposer	UK Power Reserve
Demand TNUoS Embedded benefit for the affected generators	New Embedded Generators would receive zero embedded benefit (neither the locational nor the residual)
Affected Embedded Generators who have a different value of the embedded benefit	All new embedded generation after 30 June 2017, except if it has a CM or CFD contract achieved in the 2014 and 2015 auctions which can still commission after the 30 June 2017 and not be impacted by this proposal.
Implementation Date	1 April 2017

Table 14: Summary of UKPR's potential alternative proposal for CMP264

4.3 UK Power Reserve have raised potential alternatives to the original modification proposed by Scottish Power. This alternative modification is similar in principle to the original however suggests amendments to the definition of ‘New Embedded Generator’ and ‘Commissioned’.

4.3.1 As per the original modification, as extracted below,

This modification aims to limit the detriment from the continuing lack of a level playing field between new embedded generators and other generation plant, by suspending access to Triad avoidance for New Embedded Generators until Ofgem has completed its consideration of the issues (including any review which may ensue) and fully implemented any resulting changes. New Embedded Generator is defined as any half hourly metered embedded generation unit commissioned after 30 June 2017.

4.3.2 The alternative modification proposes an amendment to the definition of ‘Commissioned’ as follows.

Commissioned is defined as having an MPAN registered and having commenced generation. The suspension is achieved by removing the netting of output from New Embedded Generators when calculating their demand volumes for use in the setting of tariffs for suppliers in the Transport and Tariff model and for actual billing. As the supplier would no longer benefit from netting the output from these generators there will be no “Triad avoidance” to share with the embedded generator.

Any new build distributed CMU that has secured a 2014 or 2015 T-4 capacity market or contract for difference agreement and has passed its financial commitment milestone by the 30 June 2017 is also included as being commissioned. For clarity this does not require the site to have generated by this date.

4.3.3 As per the original modification, as extracted below,

It is intended that the changes to the charging methodology made by this modification will be temporary and that no enduring difference of treatment between new and existing generation will be created. Accordingly, the provisions of this modification that change the charging methodology will cease to have effect on the “disapplication date, being the date when Ofgem confirms that it has completed its consideration of the issues (and any review which may ensue) and any resulting changes have been fully implemented.

A BSC amendment would amend the metering data reports to provide the information needed in order to remove the netting for all embedded generators commissioned after 30 June 2017.

4.3.4 This alternative modification to the Original proposal is designed to exclude sites with pre-agreed capacity market and contracts for difference notifications from being impacted unfairly by the decision to remove embedded benefits from them.

4.3.5 This alternative modification intends to allow 2014 and 2015 new build contracts, either under the capacity market or contracts for difference schemes that complete their financial milestones in time for the execution of this modification to still receive their embedded benefit as is the current situation (failure to complete the financial milestones by this date would trigger termination provision of the capacity market agreement for the new build in any case).

4.3.6 The justification for this alternative modification is that the commercial and investment decision to bid and build new embedded assets during 2014 and 2015 was taken under the premise that embedded benefits would be in place for the duration of the capacity agreement awarded (T-4 for 15 years). The removal of that benefit under the original modification proposal would therefore have a significant impact on the viability of this capacity being developed, it would also put the impacted 2014 and 2015 new build Capacity Market Units (CMUs) in a potential termination position. The benefit of this new build capacity has already been priced into the capacity market and security of supply until 2035 and therefore the end consumer has benefitted from this capacity being secured over the duration of these agreements as per the design and rules of the capacity market at that time. It should also be noted that just prior to the 2014 Capacity Market auction National Grid has just concluded a review of the embedded benefits and concluded not to make any changes.

4.3.7 UKPR believe the original modification would remove revenue for sites that have already secured contracts and therefore, would represent discrimination and be detrimental to competition and the principle of the level playing field. The original modification therefore fails to meet objective A of the CUSC charging objectives. The alternative proposal would address the defects and make CMP264 forward looking rather than potentially retrospective in its application.

4.3.8 UKPR believe the alternative proposal improves the Original as it:

(a) Does not discriminate against investment decisions already made that under the new build CM/CfD contracts have until June 2017 to pass their financial milestone and until October 2019 to commission.

(b) Better facilitates competition in that new build capacity already awarded through the CM/CfD have done so through competitive auctions and to adopt the Original could put capacity into termination provisions and reduce competition in the wholesale and ancillary markets in future as this capacity would not be built to compete.

(c) Better reflecting costs. New builds already awarded long term capacity agreements have reduced the CM/CfD costs and this has in turn reduced costs/volumes required for procurement over the duration of the agreements delivering a cost benefit to the end consumer.

4.3.9 The current proposal suggests that Triad avoidance values are non-cost reflective and are overvalued approximately by a factor of twenty, forming the basis to remove embedded benefits for small-scale embedded generation. UKPR note that the analysis was undertaken by National Grid in the recent review and consultation of embedded benefit which concluded in 2014. The analysis undertaken is far from conclusive and also could be argued that potential conflicts of interest should be flagged as National Grid could be seen to benefit under its Transmission Operator Licence from increased usage of the Transmission System and therefore anything relating to reducing revenue or increasing costs for demand side response/distributed generation or reducing the need for the Transmission System has to be taken into consideration when contemplating the analysis used. UKPR would state the reasoning for these modifications is yet to be agreed/set out by Ofgem and the direction of travel is yet to be published as indicated prior to the 2016 capacity market prequalification round. Currently there exists no consensus on this issue. Whilst the value of Triad avoidance is pending review by Ofgem, its is proposed that existing and committed investments in capacity are safeguarded from the Original modification through our proposed alternative. This is to ensure that this proposal does not have the unintended consequence of causing further distortion to the market.

4.3.10 In addition to the impact on market distortion, the current proposal is highly likely to cause disruption to security of supply in the market, and undermines government procured capacity. "An immediate removal of embedded benefits could make a proportion of existing distributed generation uneconomic. UKPR estimate that if embedded benefits were removed for recently awarded new build capacity, approximately 2,100MW of new distributed generation in the T-4 2014 and 2015 auctions could be withdrawn. This withdrawal could have significant impacts on near term security of supply."[43] (KMPG report for UK Power Reserve, May 2016: 'The effects of changes to embedded benefits on the Energy Trilemma'). This also forms the basis to safeguard existing and committed investments in capacity to avoid significantly increasing the costs to the end consumer (>£1bn incremental) in future capacity market auctions to procure replacement new build capacity at much higher prices. Furthermore this capacity and its providers would potentially have to pay up to £50m in termination penalties on failure to meet their commitments due to projects being placed in a distressed position.

4.3.11 This alternative modification is therefore designed to exclude new build sites with pre-agreed Capacity Market and Contracts for Difference notifications that are already in place prior to the existence of the modification from being retrospectively penalised by the Original proposal. This alternative modification amends the proposed gross charging treatment of TNUoS to apply to all future new build capacity entered into from 2016 in Capacity Market or Contract for Difference arrangements that is not commissioned prior to 30 June 2017. This is to allow a level playing field between the two support arrangements of the capacity market and the contracts for difference schemes and ensures the cost reflective value secured through these projects is delivered to the end consumer.

4.3.12 The justification for this alternative modification is that the commercial and investment decision to bid and build new embedded assets during 2014 and 2015 was taken under the premise that embedded benefits would be in place. The removal of that benefit under the Original modification proposal would therefore have a significant impact on the viability of this capacity being developed, it would also put the impacted 2014 and 2015 new build Capacity Market Units (CMUs) in a potential termination position.

4.3.13 Furthermore the additional competition of new build distributed generation in the EMR auctions during 2014 and 2015 has lowered the clearing prices and locked into these prices over the term of the contracts delivering this value to the end consumer. The Capacity Market auction was specifically designed to be complimentary to other non-excluded revenues streams as advocated by Ofgem and DECC and therefore it was reasonable for distributed generation to assume embedded benefits were bankable when bidding for and securing long term EMR agreements out to 2034 & 2035 to meet their investment case. Ofgem made public statements in the run up to the 2014 Capacity Market auction encouraging specifically Capacity Market participants to factor in their business plans impacts from certain reforms that were yet to be agreed such as the Electricity Balancing Significant Code Review (EBSCR) outcome on Cash Out Reform despite Ofgem rejecting P304 and P314 just prior to the December 2014 Capacity Market auction[44]. It is therefore reasonable to assume the embedded benefits should be factored in to participants bidding in the EMR auctions given a review had only just concluded in 2014 and no changes were proposed to the existing arrangements and furthermore no planned changes were on the horizon from National Grid or Ofgem.

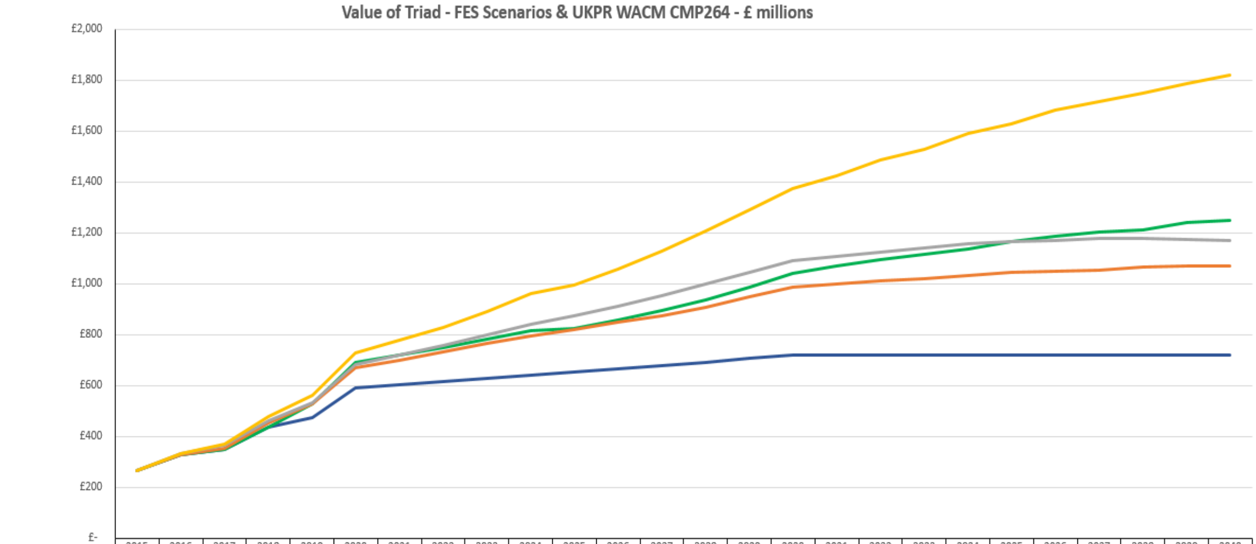
[43] http://www.smartestenergy.com/info-hub/the-informer/removing-embedded-benefits-could-dent-energy-security-warns-report/

[44] https://www.ofgem.gov.uk/sites/default/files/docs/2014/10/statement_on_our_commitment_to_the_ebscr_reforms_0.pdf

4.3.14 The Original modification would remove revenue for committed investments that have already secured contracts therefore represents discrimination and creates a negative impact on competition and goes against the principle of a level playing field. The Original modification therefore fails to meet objective A of the CUSC charging objectives. The alternative proposal would address this defect and makes CMP264 forward looking rather than retrospective in its application.

4.3.15 Furthermore, in the previous informal embedded benefits review consultation responses, the Original proposer submitted to National Grid a response that advocated for grandfathering and/or protection of charging arrangements should any changes be forthcoming relating to embedded benefits or the discount applicable under the C13 licence condition[45]. The proposer also was clearly supportive of net charging arrangements as referenced in pages 12-14 of the linked document. Given the main industry changes since this submission has been the implementation of the Capacity Market and the Contracts for Difference and the results from the recent auctions. Therefore UKPR feels the proposed alternative better align to the CUSC objectives than the Original.

4.3.16 In Figure 12, UK Power Reserve have analysed the projected value of Triad through the use of National Grids Future Energy Scenarios in combination with KPMG derating factors up to 2040 to project the growth of Triad payment via the TNUoS methodology. The alternative proposal that UK Power Reserve has proposed would restrict this growth in line with the original modification so as to effect a reduction of £1.1 billion by 2040 through the removal of Embedded benefits to New Build capacity.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
UKPR CMP265	£265	£328	£348	£437	£473	£591	£602	£614	£627	£639	£652	£665	£678
Gone Green	£265	£328	£348	£437	£527	£691	£720	£749	£781	£815	£824	£858	£895
Slow Progress	£265	£328	£354	£451	£527	£670	£699	£734	£764	£797	£819	£848	£875
No Progress	£265	£332	£364	£463	£532	£682	£718	£759	£799	£840	£874	£913	£952
Consumer Power	£265	£334	£368	£480	£561	£728	£777	£829	£891	£960	£997	£1,058	£1,126

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
UKPR CMP265	£692	£706	£720	£720	£720	£720	£720	£720	£720	£720	£720	£720	£720
Gone Green	£937	£986	£1,041	£1,070	£1,095	£1,114	£1,138	£1,166	£1,188	£1,202	£1,213	£1,240	£1,248
Slow Progress	£909	£949	£985	£997	£1,010	£1,019	£1,033	£1,046	£1,049	£1,054	£1,067	£1,068	£1,069
No Progress	£1,001	£1,045	£1,090	£1,108	£1,124	£1,140	£1,158	£1,164	£1,171	£1,177	£1,178	£1,174	£1,169
Consumer Power	£1,209	£1,291	£1,373	£1,427	£1,487	£1,527	£1,592	£1,629	£1,682	£1,714	£1,751	£1,786	£1,822

Figure 12: Projected value of Triad through the use of National Grids Future Energy Scenarios in combination with KPMG derating under UKPR (1)

[45] http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=32671

Applicable to CMP265: UK Power Reserve (2)

	UKPR (2)
Proposer	UK Power Reserve
Proposal	Include certain embedded generation (those with Capacity Market contracts) within the demand charging base for a supplier, so that demand TNUoS embedded benefit are removed for those generators.
Affected Embedded Generators who have a different value of the embedded benefit	All embedded generators with a capacity market contract, and those with a CFD agreement after 1st April 2016
demand TNUoS Embedded benefit for the affected generators	Affected embedded generators would receive the locational TNUoS tariffs as an embedded benefit, but zero residual.
Implementation Date	1 April 2020

Table 15: Summary of UKPR's potential alternative proposal for CMP265

4.3.17 UK Power Reserve have raised this potential alternative to the original modification proposed by EDF.

4.3.18 It is proposed that half hourly demand residual TNUoS charges on each Supplier in the relevant GSP Group, should be levied according to gross half hourly metered demand, without the volume from new build embedded generation that is in the capacity mechanism or contract for difference schemes being netted-off. The scope of the modification is limited to only embedded distributed generation with new build capacity market contracts or contracts for difference that were notified after 1st April 2016. The implementation date for gross calculation for TNUoS charges would be the 1st April 2020. Capacity market units with new build capacity market or contract for difference contracts notified prior to this date will be unaffected for the duration of their contract.

4.3.19 Volume associated with embedded generation that is either existing or holds a 2014 or 2015 new build capacity market or contracts for difference agreements will continue to be netted for the half hourly demand residual TNUoS charges.

4.3.20 As per the original modification, as extracted below,

It is proposed that half hourly demand locational TNUoS charges on each Supplier in the relevant GSP Group, should still be levied in relation to the net demand, i.e. with embedded generation still being netted-off as at present to enable this cost reflective signal to be maintained.

It is likely that a new data flow to National Grid is needed to facilitate this; we are proposing to raise a BSC Modification (possibly preceded by a BSC issues group to identify the best solution) to ensure that this flow exists. This is a significant modification proposal and a lead time of several charging years before the proposed change takes effect may be sensible to allow parties time to adjust, recognising that some future investments have not been made yet. The next capacity market auction (for winter 2020/21) takes place in December.

4.3.21 This alternative modification to the Original proposal is designed to exclude sites with pre-agreed capacity market and contracts for difference notifications that are already in place prior to this modification from being retrospectively penalised by the decision to remove embedded benefits from them.

4.3.22 The alternative modification also extends the proposed gross charging treatment of TNUoS to capacity entering into a new contract for difference agreement after the cut-off date of 1st April 2016, this is to allow a level playing field between the two support arrangements of the capacity market and the contracts for difference schemes.

4.3.23 DSR units are only eligible for 1 year capacity market deals and we deem that they should therefore be unaffected by this proposal.

4.3.24 The justification for this alternative modification is that the commercial and investment decision to bid and build new embedded assets during 2014 and 2015 was taken under the premise that embedded benefits would be in place. The removal of that benefit under the original modification proposal would therefore have a significant impact on the viability of this capacity being developed, it would also put the impacted 2014 and 2015 new build Capacity Market Units (CMUs) in a potential termination position.

4.3.25 The original modification would remove revenue for sites that have already secured contracts and therefore, would represent discrimination and be detrimental to competition and the principle of the level playing field. The original modification therefore fails to meet objective A of the CUSC charging objectives. The alternative proposal would address the defects and make CMP264 forward looking rather than potentially retrospective in its application.

4.3.26 Existing assets that would secure capacity market agreements are capped by the price taker threshold of £25/kW unless they are capable of claiming price maker status. Therefore, they should not be impacted by this proposal as they cannot distort the market under the existing capacity market rules any more than an existing transmission connected asset could do so.

4.3.27 UKPR believe the alternative proposal improves the CMP265 Original as it:

(a) Does not discriminate against new build capacity market embedded generation CMUs awarded agreements in 2014 and 2015 but instead focuses on new builds in both EMR auctions going forward (as these projects can price known revenue arrangements into their auction bids).

(b) Does not discriminate against existing capacity market embedded generators whom are capped at the price taker threshold and 1 year agreements and therefore this capacity cannot distort the capacity market as proposed by the Original.

(c) Does not distort competition by potentially removing significant volumes of existing embedded generation from the capacity market and increasing costs for the end consumer.

(d) Does not discriminate between behind the meter and in front of the meter embedded generation and DSR as these now fall out of scope under the alternative.

(e) Introduces the same principle to apply to Contracts for Difference in order to ensure the level playing field and not distort or discriminate against a particular class of distributed generation over another.

(f) Changes the implementation date to coincide with commencement of capacity market payments so to remove as many market distortions as possible as a result of future new build capacity securing new build EMR agreements and new contracted capacity being commissioned earlier than 2020/21.

(g) The current proposal suggests that Triad avoidance is distortive to the Capacity Market and thus also forms the basis to remove embedded benefits for small-scale embedded generation. We would highlight that the original proposer has arguably created much greater distortions in the Capacity Market as recently announced in the 2020 Capacity Market parameters by Amber Rudd through the proposers failure to meet committed obligations within the capacity market on two large transmission connected existing CMUs totalling 3.5GWs (West Burton and Cottam) which is comparable to the entirety of existing and new build distributed generation participating in the capacity market to date[46]. These transmission connected sites represents some 7% of the total capacity market contracted volume and this capacity has to date failed to meet its capacity market commitments potentially distorting the capacity market delivery years of 2018 – 2036. To put this into context this represents 7% of the total cost of the capacity market which annually over the period could cost consumers between £1bn - £3bn per annum

4.3.28 UKPR would state the reasoning for the Original modifications is yet to be agreed/set out by Ofgem and the direction of travel is yet to be published as indicated prior to the 2016 capacity market prequalification round. Currently there exists no consensus on this issue. Whilst the value of Triad avoidance is pending review by Ofgem, we propose that existing and committed investments in capacity are safeguarded from the Original modification through our proposed alternative. This is to ensure that this proposal does not have the unintended consequence of causing further distortion to the market.

4.3.29 In addition to the impact on market distortion, the current proposal is highly likely to cause disruption to security of supply in the market, and undermines government procured capacity. From analysis presented in the May 2016 KMPG report for UK Power Reserve a removal of embedded benefits could make a proportion of both existing and new build distributed generation uneconomic. We estimate that if embedded benefits were removed for all plant, approximately 4,400MW of new and existing distributed generation could be withdrawn or shut down[47]. This could have significant impacts on near term security of supply, especially as KPMG state "Distributed generation no longer supplies power at peak leading to an increased risk of blackouts, build constraints on new CCGTs mean this capacity cannot be instantly replaced and successful new build plant in Capacity market auctions are unable to reach financial close". (KMPG report for UK Power Reserve, May 2016: 'The effects of changes to embedded benefits on the Energy Trilemma').

4.3.30 Furthermore UKPR estimate to replace this capacity with transmission connected new build capacity in future capacity market auctions could increase costs significantly (>£2.5bn) paid for by the end consumer.

46 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/536015/Amber_Rudd_Letter.pdf

47 http://www.smartestenergy.com/info-hub/the-informer/removing-embedded-benefits-could-dent-energy-security-warns-report/

4.3.31 This alternative proposal is therefore designed to exclude existing and new build sites with pre-agreed Capacity Market and Contracts for Difference notifications that are already in place prior to the existence of the modification from being retrospectively penalised by the Original proposal. This alternative modification amends the proposed gross charging treatment of the residual element of TNUoS to only apply to future new build capacity entered into from 2016 in Capacity Market or Contract for Difference arrangements. This is to allow a level playing field between the two support arrangements of the capacity market and the contracts for difference schemes and ensures the cost reflective value secured through these projects is delivered to the end consumer.

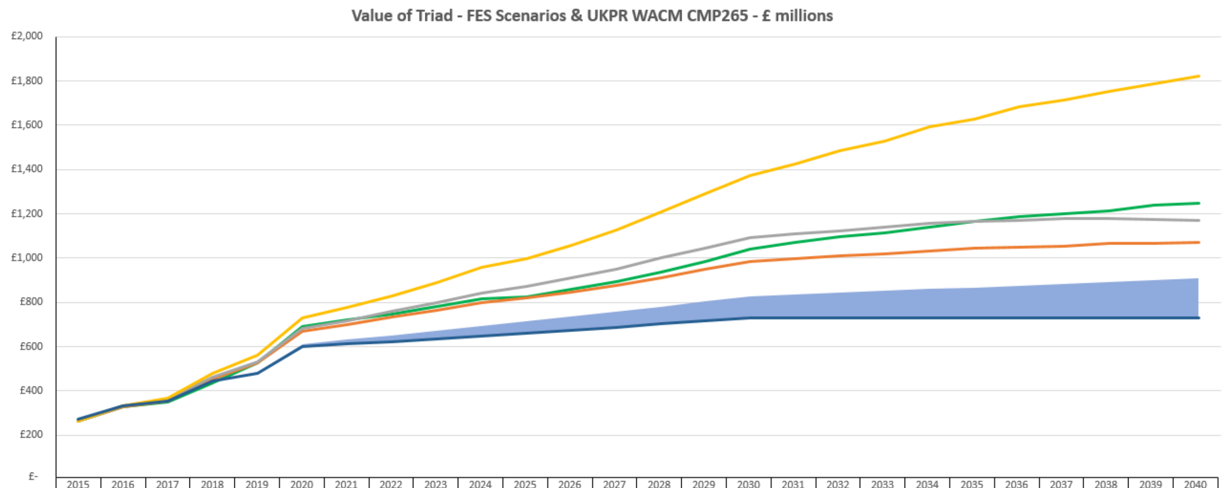
4.3.32 The justification for this alternative modification is that the commercial and investment decision to bid and build new embedded assets during 2014 and 2015 was taken under the premise that embedded benefits would be in place. The removal of that benefit under the Original modification proposal would therefore have a significant impact on the viability of this capacity being developed, it would also put the impacted 2014 and 2015 new build Capacity Market Units (CMUs) in a potential termination position. The Original modifications exclusion of Contract for Difference schemes would also lead to a significant discrimination in the market, especially favouring renewable distributed capacity and demand side response CMUs whom would still receive significant benefit from both schemes.

4.3.33 In the previous informal embedded benefits review consultation responses, the Original proposer submitted to National Grid a response that advocated for grandfathering and/or protection of charging arrangements should any changes be forthcoming relating to embedded benefits.

4.3.34 The main industry changes since this submission has been the implementation of the Capacity Market and the Contracts for Difference and the results from the recent auctions.

4.3.35 The Original modification would represent discrimination and distortions far greater than the cited issue it is looking to address and creates a negative impact on competition and goes against the principle of a level playing field. The Original modification therefore fails to meet objective A of the CUSC charging objectives. The alternative proposal would address this defect and makes CMP265 forward looking rather than retrospective in its application.

4.3.36 In Figure 12, UK Power Reserve have analysed the projected value of Triad through the use of National Grids Future Energy Scenarios in combination with KPMG derating factors up to 2040 to project the growth of Triad payment via the TNUoS methodology. The potential alternative proposal that UK Power Reserve has proposed would restrict this growth in line with the original modification so as to effect a reduction of £1.1 billion by 2040 through the removal of Embedded benefits to New Build capacity. However, under this modification it is important to note that there would be the potential for generators to opt to receive Triad revenue in exchange for forgoing Capacity Market or Contract for Difference revenue, although it is difficult to forecast this behavioural decision in the market the below scale represents the potential for embedded generators to favour receipt of Triad over the CM or CfD schemes.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
UKPR CMP265	£265	£328	£348	£437	£473	£591	£602	£614	£627	£639	£652	£665	£678
Gone Green	£265	£328	£348	£437	£527	£691	£720	£749	£781	£815	£824	£858	£895
Slow Progress	£265	£328	£354	£451	£527	£670	£699	£734	£764	£797	£819	£848	£875
No Progress	£265	£332	£364	£463	£532	£682	£718	£759	£799	£840	£874	£913	£952
Consumer Power	£265	£334	£368	£480	£561	£728	£777	£829	£891	£960	£997	£1,058	£1,126

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
UKPR CMP265	£692	£706	£720	£720	£720	£720	£720	£720	£720	£720	£720	£720	£720
Gone Green	£937	£986	£1,041	£1,070	£1,095	£1,114	£1,138	£1,166	£1,188	£1,202	£1,213	£1,240	£1,248
Slow Progress	£909	£949	£985	£997	£1,010	£1,019	£1,033	£1,046	£1,049	£1,054	£1,067	£1,068	£1,069
No Progress	£1,001	£1,045	£1,090	£1,108	£1,124	£1,140	£1,158	£1,164	£1,171	£1,177	£1,178	£1,174	£1,169
Consumer Power	£1,209	£1,291	£1,373	£1,427	£1,487	£1,527	£1,592	£1,629	£1,682	£1,714	£1,751	£1,786	£1,822

Figure 13: Projected value of Triad through the use of National Grids Future Energy Scenarios in combination with KPMG derating under UKPR (2)

Summary:

4.3.37 As stated in 4.1.3 these alternative proposals were not fully debated by the Workgroup. The views stated in section 4 are therefore primarily those of the proposer of the alternative and are not necessarily supported by all Workgroup members.

4.3.38 Respondents to this consultation may provide suggested alternates. Please see section 6.3.2 for how to raise an alternative proposal and a link to the proforma to be used.

5 Impact and Assessment

5.1 Impact on the CUSC

5.1.1 Both CMP264 and CMP265 would require changes to Section 14 of the CUSC.

5.1.2 There is also potential that other consequential changes may also be required to other sections of the CUSC, and in this situation another modification(s) would need to be raised against a defect in the relevant section against the general CUSC objectives. A defect in Section 14, assessed on the CUSC Charging Objectives, can only make changes to Section 14 only. Depending on the nature of the consequential changes, it may be possible to include these within Section 14, negating the need for a further modification.

5.2 Impact on Greenhouse Gas Emissions

5.2.1 The workgroup has not assessed the impact on Greenhouse Gas Emissions.

5.3 Impact on Core Industry Documents

5.3.1 None

5.4 Impact on other Industry Documents

5.4.1 There is likely to be an impact on the Balancing and Settlement Code, to provide the required data flows.

(a) In particular P349: Facilitating embedded generation Triad Avoidance Standstill was raised on 4 July, to accompany CMP264, and P348: Provision of gross BM Unit data for TNUoS charging was raised on 1 July to accompany CMP265. ELEXON are involved in the discussion within the CMP264 and CMP265 Workgroups to improve synergies between CMP264/P349 and CMP265/P348.

(b) There may also be consequential changes to the MRA Data Transfer Catalogue (DTC), identified through the related BSC modifications.

5.4.2 Although none have been identified yet, there may be changes to the capacity market rules needed to ensure that all plant can be identified.

6 Proposed Implementation and Transition

6.1 CMP264 Original Proposal

6.1.1 It is proposed to make changes to the charging methodology (Section 14) of the CUSC with effect of **1 April 2017**, so that the new charging regime applied from charging year 2017/18 onwards.

6.1.2 No transitional arrangements are required.

6.2 CMP265 Original Proposal

6.2.1 It is proposed to make changes to the charging methodology (Section 14) of the CUSC with effect of **1 April 2020**, so that the new charging regime applied from charging year 2020/21 onwards.

6.2.2 No transitional arrangements are required to charging methodologies; however, given the lead time to implementation there may be a need to capture the information in the charging methodology as future change methodology to provide clarity over the 3-year period.

6.2.3 Parties are invited to respond on the appropriateness / achievability of these timescales through the standard consultation questions (Question 2 for CMP264, and Question 6 for CMP265).

6.3 Implementation for potential alternatives

6.3.1 Timescales for implementations of the particular alternative were discussion in Section 5. Workgroup members seek the views of members on the view of the suggested implementation dates of the proposal alternatives. If you intend to raise an alternative proposal for the Workgroup to consider raising as a formal WACM please use http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/modifications/forms-and-guidance/

6.3.2 Please note any proposed alternatives clearly need to define the rationale how it betters addresses the scope of the defect for CMP264 and CMP265. The Workgroup will consider any proposals and voted on those that it considers should become a WACM. The Code Administration consultation (put when due) will be the opportunity of industry to review and respond to the formal WACMs of the Workgroup.

Consultation Question 19: Applies to CMP264 and CMP265

Regarding the proposed alternatives what are your views on the suggested implementation dates? Are these achievable? Please give reasons for your view.

7 Question for Consultation

7.1 Summary

7.1.1 For the avoidance of doubt this document results in two separate consultations, however, the workgroup recognises the similarity in the technical discussion as has presented the material as a collated document.

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

7.2 Standard Workgroup Consultation questions:

		CMP264
1		Do you believe that CMP264 Original proposal or either of the associated potential options for change better facilitates the Applicable CUSC Objectives?
2		Do you support the proposed implementation approach for CMP264? Are the suggested implementation timescales suggested for CMP264 appropriate / achievable?
3		Do you have any other comments for CMP264?
4		Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider for CMP264? Please see 6.3
		CMP265
5		Do you believe that CMP265 Original proposal or either of the associated potential options for change better facilitates the Applicable CUSC Objectives?
6		Do you support the proposed implementation approach for CMP265? Are the suggested implementation timescales suggested for CMP265 appropriate / achievable?
7		Do you have any other comments for CMP265?
8		Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider for CMP265? Please see 6.3.

7.3 Further Workgroup questions

Specific questions for CMP264

		CMP264
10		i) Do you think a cut-off date for "new embedded generation" of 30 June 2017 is appropriate? What other date would you propose? ii) Do you have any views on how mixed sites are being addressed in CMP264 Original? iii) Do you think new-build embedded generation capacity that has entered into long term

		financial and performance commitment obligations via 2014 and 2015 capacity market or contracts for difference auctions (prior to this modification proposal) should be given exceptions to this cut-off date? iv) Do you agree that ignoring demand behind the meter is unlikely to create a significant "loophole" or material discrimination risk in relation to the CMP264 arrangements in the short term v) Question to suppliers: Do you consider that the wording of your existing contracts allow you to reflect the changes provided by these modifications in a cost reflective manner. For example, these changes will apply to existing PPAs and generators who significantly alter their output (EREC 59). **vi)** Do you agree with the definition of commissioned and do you agree that it is appropriate? If you do not agree with the definition or that it is appropriate please provide alternative definitions and rationale for this definition.
13		Do you have a view of whether implementation for the 2017/18 Triad season is sufficient to allow changes for: i) supplier contracts and billing system; and ii) for other stakeholders?
18		Do you have a view if embedded benefits are frozen at a non-zero value, what should that value be as a £/kW tariff (2016/17 value is £45.33 / kW)?

Specific questions for CMP265

		CMP265
11		i) Views are sought on the implication for mixed sites discussed in 3.4.10. ii) Views are sought on the preference of categories of capacity Market CMU captured by this proposal, please indicate your preference from the following list and reasons: • All existing and new distribution generation CMUs • All existing and new distribution generation CMUs and DSR CMUs (proven and unproven) • All price maker CMUs • All newbuild/prospective distribution generation CMUs only (defined as >1year contracts)
14		Do you have a view of whether implementation for the 2020/21 Triad season is sufficient to allow changes for i) supplier contracts and billing system, and ii) for other stakeholders?

Questions for both CMP264 and CMP265

		CMP264 and CMP265
9		i) Suppliers: In setting charges for your demand customers, do you charge them at the same tariff as National Grid charges you (i.e. gross), to enable you to pay the embedded benefit to embedded generators, or please explain the way in which it is funded? ii) Suppliers: Does the estimate that 7.58GW of embedded generation output and

		2.5GW of demand side reduction at the time of Triad for 2016/17 seem reasonable based on your knowledge of the UK market? If not what is your estimate of embedded generator output and DSR at time of Triad?
12		Can you identify – either quantitatively or qualitatively - the impact of the demand TNUoS embedded benefit on your decisions made in making capacity market decisions?
15		i) What are your views on the 2 broad options to enable the reporting of gross export metered data? ii) Would you have the data available required for Option B (both CMP264 and CMP265) for both new contracts and existing contracts where a customer may be partially exempt? iii) Do you believe you can implement the proposed changes by the respective implementation dates? iv) What are the pros and cons of the 2 proposals that ELEXON are considering to implement this (P348 for CMP265/ P349 for CMP264)?
16		Do you have any further evidence / comments on the consumer impact of changing the demand TNUoS embedded benefit in either the short-run or long-run?
17		Do you feel that both the locational and residual component of the demand TNUoS should be removed as an embedded benefit (as CMP264 Original) or just the residual component (as CMP265 Original) or some other method?
19		Regarding the proposed alternatives what are your views on the suggested implementation dates? Are these achievable? Please give reasons for your view.

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

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP264/

http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP265/

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

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

7.3.4 Views are invited upon the proposals outlined in this report, which should be received by 5pm on 24 August 2016. Your formal responses may be emailed to: cusc.team@nationalgrid.com.

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

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

Annex 1. CMP264: Proposal Form

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMPXXX

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal

Embedded Generation Triad Avoidance Standstill proposal – Changes to the Transport and Tariff Model and billing arrangements to remove the netting of output from New Embedded Generators until Ofgem has completed its consideration of the current electricity transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented.

Submission Date

17 May 2016

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

The registration of embedded generators to a Supplier BM Unit can result in a reduction in TNUoS charges payable by the supplier. The embedded generators do not pay generation transmission charges and may receive a significant benefit from the supplier whose TNUoS charges they reduce – "Triad avoidance".

Due to increasing volume of embedded generation output and the growth in the Transmission Owner Allowed Revenues and other monies recoverable through TNUoS, the likely value of Triad avoidance for embedded generators has increased significantly, and under the current charging arrangements is forecast by National Grid Electricity Transmission ("NGET") to continue to grow. If Triad avoidance (and the future increases) were cost-reflective in terms of the transmission reinforcement avoided by reducing flows from the transmission system to meet demand, then the current arrangements would be in the interest of consumers. However, whilst analysis[1] by NGET suggests that some transmission investment is avoided by such reductions in flows, the savings appear to be around twenty times too small to justify current Triad avoidance values. In that work, NGET determined that the average cost saving was £1.62/kW/year in 2013/14 money, whilst a current estimate[2] of the average value that an embedded generator would receive from Triad avoidance in 2018/19 is around £45/kW/year[3]. Moreover, the results from 5 out of the 18 schemes that were assessed showed cost savings of less than 50p/kW/year.

The existence of large non-cost reflective Triad avoidance values is likely to distort investment decisions by favouring small generation units over large ones that may be more efficient. This could cause more efficient investments which do not benefit from Triad avoidance to be abandoned or deferred while less effective ones, which do so benefit, go ahead. This would increase total system costs, which is likely to lead to higher costs for consumers. Cost reflective charges would lead to better investment decisions and lower costs for consumers.

Ofgem is currently considering these issues[4] and implementation of any resulting changes, eg through a Significant Code Review (SCR), is likely to take some time. In the meantime, distortions to investment could take place based on the current non-cost reflective signals, in part due to Triad avoidance income received during the period of the review. This is likely to lead to inefficient investment in the generation fleet and, over time, higher costs for customers. This risk can be mitigated by suspending access to Triad avoidance for New Embedded Generators until Ofgem's consideration of the current electricity transmission Charging Arrangements (and any review which may ensue) has been completed and any resulting changes have been fully implemented.

This is a proportionate response since current indications are that Triad avoidance values exceed the cost reflective level by a factor of around 20. It follows that temporarily setting them to zero for new embedded generators is likely to be closer to the cost reflective outcome, and more likely to be efficient for consumers, than allowing the current situation to sustain pending Ofgem's consideration of the issues (including any review which may ensue) and implementation of any more comprehensive changes.

[1] National Grid, Review of the Embedded (Distributed) Generation Benefit arising from transmission charges, 20 December 2013.
[2] National Grid outlook January 28th 2015 (http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Approval-conditions/Condition-5/)
[3] The current value of Triad management is £30/kW/year, but this is forecast to rise by around £15/kW/year by 2018/19. This estimate excludes the three least lucrative geographical areas - the locational signal may mean that these areas are not targeted by developers.
4 As recently announced by DECC and highlighted in Ofgem's Forward Work Programme 2016-17 paras 2.17 to 2.19

Description of the CUSC Modification Proposal

This modification aims to limit the detriment from the continuing lack of a level playing field between new embedded generators and other generation plant, by suspending access to Triad avoidance for New Embedded Generators until Ofgem has completed its consideration of the issues (including any review which may ensue) and fully implemented any resulting changes.

New Embedded Generator is defined as any half hourly metered embedded generation unit commissioned after 30 June 2017.

Commissioned is defined as having an MPAN registered and having commenced generation.

The suspension is achieved by removing the netting of output from New Embedded Generators when calculating their demand volumes for use in the setting of tariffs for suppliers in the Transport and Tariff model and for actual billing. As the supplier would no longer benefit from netting the output from these generators there will be no "Triad avoidance" to share with the embedded generator.

It is intended that the changes to the charging methodology made by this modification will be temporary and that no enduring difference of treatment between new and existing generation will be created. Accordingly, the provisions of this modification that change the charging methodology will cease to have effect on the "disapplication date, being the date when Ofgem confirms that it has completed its consideration of the issues (and any review which may ensue) and any resulting changes have been fully implemented.

A BSC amendment would amend the metering data reports to provide the information needed in order to remove the netting for all embedded generators commissioned after 30 June 2017.

Impact on the CUSC

Changes will be required to Section 14 of the CUSC (Part 2 The Statement of the Use of System Charging Methodology) including, but not necessarily limited to the following:

Tariff Setting

Changes are required to Section 14.15 (Derivation of the Transmission Network Use of System Tariff) to ensure that total User forecast Metered Triad Demand provided by Users and used to set TNUoS tariffs does not net any output from New Embedded Generation.

Billing & Reconciliation

The basis of Demand Charges should be amended to ensure that output from any New Embedded Generators is not netted from Triad demand in the Supplier forecasts used for monthly billing or in the reconciliation process to actual outturn charges.

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

You can find guidance on the treatment of carbon costs and evaluation of the greenhouse gas emissions on the Ofgem's website:
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=196&refer=Licensing/IndCodes/Governance

We believe that this Proposal is likely to help reduce greenhouse gas emissions. This is as a result of the creation of a level playing field between small embedded generation and larger transmission connected generation. We believe that this is likely to lead to the deployment of more efficient plant which may lead to a corresponding reduction in the emission of greenhouse gasses.

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

BSC ☒

Grid Code ☐

STC ☐

Other ☐
(please specify)

This is an optional section. You should select any Codes or state Industry Documents which may be affected by this Proposal and, where possible, how they will be affected.

The data used in the calculation of Triad demand and chargeable supplier demand volumes is calculated under the Balancing & Settlement Code (BSC) and changes will be required to the BSC to enable the identification of meter data from New Embedded Generators. This meter data should then be excluded when generating the data flows used for TNUoS billing. A separate BSC Issue will be raised to consider the potential changes required from this CUSC modification.

For the avoidance of doubt, metered output from embedded generators will still be netted from Supplier's demand volumes for the purposes of imbalance settlement under the BSC.

Urgency Recommended: Yes / No

No.

Justification for Urgency Recommendation

If you have answered yes above, please describe why this Modification should be treated as Urgent. An Urgent Modification Proposal should be linked to an imminent issue or a current issue that if not urgently addressed may cause:

a) *A significant commercial impact on parties, consumers or other stakeholder(s); or*
b) *A significant impact on the safety and security of the electricity and/or has systems; or*
c) *A party to be in breach of any relevant legal requirements.*

You can find the full urgency criteria on the Ofgem's website: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=213&refer=Licensing/IndCodes/Governance

Self-Governance Recommended: Yes / No

No.

Justification for Self-Governance Recommendation

If you have answered yes above, please describe why this Modification should be treated as Self-Governance.

A Modification Proposal may be considered Self-governance where it is unlikely to have a material effect on:

- *Existing or future electricity customers;*
- *Competition in generation or supply;*
- *The operation of the transmission system;*
- *Security of Supply;*
- *Governance of the CUSC*

- *And it is unlikely to discriminate against different classes of CUSC Parties.*

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

Please justify whether this modification should be exempt from any Significant Code Review (SCR) undertaken by Ofgem. You can find guidance on the launch and conduct of SCRs on Ofgem's website, along with details of any current SCRs at: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=197&refer=Licensing/IndCodes/Governance. For further information on whether this Proposal may interact with any ongoing SCRs, please contact the Panel Secretary.

Yes. We are not aware of any current Significant Code Review (SCR) whose scope overlaps with the scope of this modification. If Ofgem opens an SCR which includes embedded generation Triad avoidance, this modification should be considered exempt because of its temporary/transitional nature.

Impact on Computer Systems and Processes used by CUSC Parties:

Suppliers will need to amend their internal systems to exclude the output from New Embedded Generators when preparing demand forecasts as required under S14 of the CUSC and when validating TNUoS bills received from National Grid.

Details of any Related Modification to Other Industry Codes

A BSC Modification will be required to provide the necessary data to facilitate this charging proposal. We shall raise a BSC Issue for consideration.

Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:

Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.

Use of System Charging Methodology

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

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

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

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

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

Full justification:

Charging Objective (a)

This modification will mitigate the effects of the current lack of a level playing field between investing in embedded generators and transmission connected (and large embedded) generators during the period of Ofgem's review, thus better facilitating competition in the generation and supply of electricity.

Charging Objective (b)
Given the low levels of actual cost savings realised through the Triad management schemes, the suspensory action would ensure that, in respect of New Embedded Generators during the period of Ofgem's review, charges would better reflect costs.

Charging Objective (c)

Developments in the transmission system have led to an increase in Triad values, thus increasing the distortions created by embedded generation Triad avoidance to an unsustainable level. This modification mitigates the effect of this by temporarily removing distortion of investment decisions until Ofgem has completed its consideration of the issues (including any review which may ensue) and fully implemented any resulting changes.

Charging Objective (d)

The proposer believes that the proposal is neutral against applicable charging objective (d).

Connection Charging Methodology

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

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

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

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

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

Full justification:

The Proposal does not impact on the Connection Charging Methodology

Additional details

Details of Proposer: (Organisation Name)	ScottishPower Energy Management Limited
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	 Rupert Steele Director of Regulation, ScottishPower 0141 614 2012 Rupert.Steele@ScottishPower.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	 James Anderson ScottishPower Energy Management Limited 0141 614 3006 James.Anderson@ScottishPower.com
Attachments (Yes/No): **If Yes, Title and No. of pages of each Attachment:**	No

Contact Us

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

E-mail cusc.team@nationalgrid.com

Phone: 01926 653606

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

Submitting the Proposal

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

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

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

Annex 2. CMP264: Terms of Reference

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP 264 WORKSHOP

CMP264 seeks to change the Transport and Tariff Model and billing arrangements to remove the netting of output from New Embedded Generators until Ofgem has completed its consideration of the current electricity transmission Charging Arrangements (and any review which ensues) and any resulting changes have been fully implemented.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP264 Embedded Generation Triad Avoidance Standstill** tabled by Scottish Power at the Modifications Panel meeting on 27 May 2016.

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

   Use of System Charging Methodology

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

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

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

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

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) The Workgroup should consider whether, on the balance of probabilities, the current level of embedded generation triad avoidance benefit significantly exceeds the actual avoided transmission investment cost, whether this causes a distortion in competition, and whether the proposed temporary removal of such benefits (pending the outcome and implementation of Ofgem's considerations) would better meet the code objectives.
b) The Workgroup should not attempt to resolve the issue of what the most appropriate charging arrangements should be on an enduring basis, as this will be the subject of Ofgem's considerations. .
c) The Workgroup should consider the definition of and criteria for the "disapplication date" in the proposed solution, i.e. the date on which the modification would cease to have effect.
d) The Workgroup should consider whether the Workgroup's conclusions would be materially impacted by the length of time between implementation and the "disapplication date".
e) The Workgroup should consider consumer impacts resulting from the proposal.
f) Consider any link to the Balancing and Settlement Code with particular focus on timescales of any changes.
g) Consider any link to EMR Settlements metering with particular focus on timescales of any changes.

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

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

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

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

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **15 working days** as determined by the Modifications Panel.

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

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

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **18 August 2016** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **26 August 2016**.

Membership

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

Role	Name	Representing
Chairman	Louise Schmitz	National Grid
National Grid Representative	Paul Wakeley	National Grid
Industry Representatives	Rupert Steele	Scottish Power (Proposer)
	James Anderson	Scottish Power
	Paul Mott	EDF
	John Tindal	SSE
	Andy Pace	Cornwall Energy
	Elizabeth Adams/Sam Wither	UK Power Reserve
	Christopher Granby	Infinis
	Bill Reed	RWE
	Lars Weber	Neas Energy
	Michael Davis	Eider Reserve Power
	Joe Underwood	Drax Power
	Simon Lord	Engie
	Tim Collins	Centrica
	Lisa Waters	Waters Wye
	Graz McDonald	Greenfrog Power

	Jonathan Graham Stephen Davies Matthew Tucker Jon Fairchild Guy Phillips John Harmer Natasha Ranatunga Herdial Dosanjh/George Douthwaite Kirsten Gardner	The ADE EON Welsh Power Peakgen Uniper Alkane EDF RWE Npower Stag Energy
Authority Representatives	Donald Smith/Dena Baresi/Dominic Green	OFGEM
Technical secretary	Caroline Wright	National Grid
Observers	Kate Dooley Nick Rubin/Talia Addy/John Lucas Bruno Menu	Energy UK ELEXON Lime Jump

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 CMP264 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 CMP264 Revised Timetable

17 May 2016	CUSC Modification Proposal submitted
27 May 2016	CUSC Modification tabled at Panel meeting
31 May 2016	Request for Workgroup members (5 Working days)
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2 November 2016 25 November 2016	Implementation date (5 Working days later)

Annex 3. CMP265: Proposal Form

CUSC Modification Proposal Form (for Charging Methodology Proposals) CMP265

nationalgrid

Connection and Use of System Code (CUSC)

Title of the CUSC Modification Proposal

Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market

Submission Date

19 May 2016

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

It is important that costs are allocated fairly as the generation mix evolves. The current TNUoS arrangements will distort the development of an economic generation mix and transmission system, distort the capacity market and continue to provide a cross subsidy between customer groups.

There is a pressing issue related to the next capacity market tender (December 2016) which means that this modification is narrow and focussed to allow the modification to be considered and determined in advance of this auction. We recognise that further changes may be needed to the TNUoS arrangements which are important but less urgent. Ofgem are likely to reach a conclusion on further charging reforms in summer 2016 and further reforms will also be a focus of National Grid's planned charging review.

Specifically, half hourly metered (HH) demand for TNUoS purposes is currently charged <u>net</u> of embedded generation. The existing CUSC sets this out as follows: "*Netting off within a BM Unit : 14.17.15 The output of generators and Distribution Interconnectors registered as part of a Supplier BM Unit will have already been accounted for in the Supplier BM Unit demand figures upon which The Company Transmission Network Use of System Demand charges are based*."

This Net demand charging means that embedded generation is being treated as negative demand for HH TNUoS demand charging purposes. The TNUoS charge can be considered as being made up of two elements :

1. A locational element reflecting the unit cost of transmission investment at a point on the GB system. At a simplified level the locational elements for generation and demand users can be considered broadly equal and opposite. Through its netting, an embedded generator can be considered to have an implicit value equal but opposite to the demand signal, and therefore equivalent to the signal received by a transmission connected generator. Given this, netting off the volume is reasonable..

2. A residual element added on a capacity basis (£/kW, irrespective of location) to ensure

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TNUoS charges recover the correct revenue. This element does not reflect cost and is worth around £40/kW.

Charging demand on a net basis means that some of the gross HH demand will not pay the residual, and neither will the embedded generation that nets off that demand.

The effect of the net demand charging basis is thus that the value of the demand residual charge element is credited to the embedded generation, where there is an association with an embedded generator as part of that Supplier's portfolio in that GSP group. This is not cost-reflective, as there is no logical reason for that credit, which is growing, to be given.

Netting-off the output of embedded generation for the purpose of calculating these HH demand charges, is causing a distortion in the generation market; to the extent that they run at times of triad, embedded generators are given an artificial advantage over others, which among other effects, distorts the outcome of the capacity market tenders.

This is most strongly apparent for controllable embedded generators that run at peak times due to the structure of the TNUoS charge. These generators are most likely to secure the majority of the avoided residual charge. It is these controllable embedded generators that are also competing in the Capacity Market and run at similar times. Correcting this defect needs to be addressed urgently in advance of the next CM auction (December 2016).

The defect therefore lies in this unwarranted distortion of capacity market tenders. The charging treatment of these generators is not reasonably reflecting transmission network costs and therefore fails against the objectives of the charging methodology. The implication of this is that it distorts competition in generation.

Description of the CUSC Modification Proposal

It is proposed that half hourly demand residual TNUoS charges on each Supplier in the relevant GSP Group, should be levied according to gross half hourly metered demand, without the volume from embedded generation that is in the capacity mechanism being netted-off. The scope of the modification is limited to only embedded generation with capacity market contracts. Volume associated with embedded generation that does not have capacity market contracts will continue to be netted.

It is proposed that half hourly demand locational TNUoS charges on each Supplier in the relevant GSP Group, should still be levied in relation to the net demand, i.e. with embedded generation being netted-off as at present to enable this cost reflective signal to be maintained.

As to the implementation timescale, we do not propose "grandfathering" which has not been an approach taken to charging modifications (it adds complexity and dilutes the effect of a change). We propose that this change would take effect from 1 April 2020, for all such generators. It is likely that a new data flow is needed to Grid to facilitate this; we are proposing to raise a BSC Modification to ensure that this flow exists. This is a significant modification proposal and a lead time of several charging years before the proposed change takes effect seems sensible to allow parties time to adjust, recognising that some future investments have not been made yet. The next capacity market auction (for winter 2020/21) takes place in

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December.

Impact on the CUSC (This is an optional section)

To be identified at workgroup. New section 11 definitions are likely to be needed; parts of section 14 are likely to need amendment.

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

Nothing quantified.

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

BSC **Yes**

Grid Code ☐

STC ☐

Other ☐
(please specify)

This is an optional section. You should select any Codes or state Industry Documents which may be affected by this Proposal and, where possible, how they will be affected.

Urgency Recommended: Yes

Yes.

Justification for Urgency Recommendation

This Modification Proposal 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). The next capacity market auction (for winter 2020/21) takes place in December; the present arrangements give an artificial advantage to embedded generators, distorting the capacity market. We therefore propose a full but expedited process that ensures that the issues are carefully considered by industry and workgroup, but that the modification proposal reaches Ofgem for decision in September.

Urgency criteria show on the Ofgem's website at :
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=213&refer=Licensing/IndCodes/Governance

Self-Governance Recommended: No

No

Justification for Self-Governance Recommendation

A Modification Proposal may be considered Self-governance where it is unlikely to have a material effect on :

- *Existing or future electricity customers;*
- *Competition in generation or supply;*
- *The operation of the transmission system;*
- *Security of Supply;*
- *Governance of the CUSC*
- *And it is unlikely to discriminate against different classes of CUSC Parties.*

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

Yes, there are no relevant SCRs

Impact on Computer Systems and Processes used by CUSC Parties:

This is an optional section. Include a list of any relevant Computer Systems and Computer Processes which may be affected by this Proposal, and where possible, how they will be affected.

Details of any Related Modification to Other Industry Codes

We will be raising a relevant BSC modification to ensure the necessary data flows are available to National Grid.

Justification for CUSC Modification Proposal with Reference to Applicable CUSC Objectives for Charging:

Please tick the relevant boxes and provide justification for each of the Charging Methodologies affected.

Use of System Charging Methodology

Yes (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;

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

Yes (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.

No (d) compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1.

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

Full justification:

The modification would better facilitate competition between transmission-connected and embedded generators with particular reference to the Capacity Market. It would remove an artificial distortion that does not reflect the costs of the transmission business and currently gives extra value to embedded generators. The present arrangements are not cost-reflective as there is no logic to netting-off the output of embedded generators from HH demand as far as the demand residual charge element is concerned. As to developments in transmission licensees' transmission businesses – there has been a marked growth in the amount of embedded generation impacting the ways the system is developed and operated – this distortion may have been a contributory factor to that.

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Additional details

Details of Proposer: (Organisation Name)	Paul Mott
Capacity in which the CUSC Modification Proposal is being proposed: (i.e. CUSC Party, BSC Party or "National Consumer Council")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	Paul Mott, EDF Energy, 02031262314 paul.mott@edfenergy.com
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	Mark Cox EDF Energy 07967151272 Mark.cox@edfenergy.com
Attachments (No): **If Yes, Title and No. of pages of each Attachment:**	

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Annex 4. CMP265: Terms of Reference

Workgroup Terms of Reference and Membership

TERMS OF REFERENCE FOR CMP265 WORKSHOP

CMP265 seeks to address the issue that half hourly metered (HH) demand for TNUoS purposes is currently charged net of embedded generation.

Responsibilities

1. The Workgroup is responsible for assisting the CUSC Modifications Panel in the evaluation of CUSC Modification Proposal **CMP265 'Gross charging of TNUoS for HH demand where embedded generation is in Capacity Market'** tabled by EDF Energy at the Modifications Panel meeting on 27 May 2016.

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

   Use of System Charging Methodology

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

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

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

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

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) This Workgroup should not focus on transmissions generator in negative zones.
   b) The Workgroup should not look to amend the existing Capacity Mechanism.
   c) The Workgroup should consider all Embedded Generation with Capacity Market contracts directly or indirectly.
   d) The Workgroup should consider consumer impacts resulting from the proposal.
   e) The Workgroup should consider whether, on the balance of probabilities, the current level of embedded generation triad avoidance benefit significantly exceeds the actual avoided transmission investment cost, whether this causes a distortion in competition, and whether the removal of such benefits (pending the outcome and implementation of Ofgem's considerations) would better meet the code objectives.
   f) Consider any link to the Balancing and Settlement Code with particular focus on timescales of any changes.
   g) Consider any link to EMR Settlements metering with particular focus on timescales of any changes.

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

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

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

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

10. There is an obligation on the Workgroup to undertake a period of Consultation in accordance with CUSC 8.20. The Workgroup Consultation period shall be for a period of **15 working days** as determined by the Modifications Panel.

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

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

12. The Workgroup is to submit its final report to the Modifications Panel Secretary on **18 August 2016** for circulation to Panel Members. The final report conclusions will be presented to the CUSC Modifications Panel meeting on **26 August 2016**.

Membership

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

Role	Name	Representing
Chairman	Louise Schmitz	National Grid
National Grid Representative	Paul Wakeley	National Grid
Industry Representatives	Paul Mott	EDF (Proposer)
	James Anderson	Scottish Power
	John Tindal	SSE
	Andy Pace	Cornwall Energy
	Elizabeth Adams/Sam Wither	UK Power Reserve
	Christopher Granby	Infinis
	Bill Reed	RWE
	Lars Weber	Neas Energy
	Michael Davis	Eider Reserve Power
	Joe Underwood	Drax Power
	Simon Lord	Engie
	Tim Collins	Centrica
	Lisa Waters	Waters Wye
	Graz McDonald	Greenfrog Power
	Jonathan Graham	The ADE
	Stephen Davies	EON
	Matthew Tucker	Welsh Power
	Jon Fairchild	Peakgen
	Guy Phillips	Uniper
	John Harmer	Alkane
	Natasha Ranatunga	EDF

	Herdial Dosanjh/George Douthwaite Kirsten Gardner	RWE npower Stag Energy
Authority Representatives	Donald Smith/Dena Baresi/Dominic Green	OFGEM
Technical secretary	Caroline Wright	National Grid
Observers	Kate Dooley Nick Rubin/Talia Addy/John Lucas Lucas Lilja Bruno Menu	Energy UK ELEXON Intergen Lime Jump

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 CMP265 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 CMP264 Revised Timetable

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Annex 6. CMP264 / CMP265 Workgroup Attendance

A – Attended

X – Absent

O – Alternate

D – Dial-in

Name	Organisation	Role	13/06/16 CMP265 14/06/16 CMP264	21/06/16	04/07/16	11/07/16	28/07/16 (teleconference)
Louise Schmitz	National Grid	Chair	A	A	A	A	AD
Ryan Place	National Grid	Technical Secretary	A	X	X	X	X
Caroline Wright	National Grid		A	A	A	X	A
Heena Chauhan	National Grid		X	X	X	A	X
Paul Wakeley	National Grid	National Grid Rep	A	A	A	A	A
John Harmer	Alkane	Workgroup member	A	AD	A	A	AD
Tim Collins	Centrica	Workgroup member	X	A	A	A	AD
George Moran	Centrica	Workgroup alternate	X	X	X	X	X
Andy Pace	Cornwall Energy	Workgroup member	A	A	X	A	AD
Tim Dixon	Cornwall Energy	Workgroup alternate	X	X	AO	X	X
Joseph Underwood	Drax Power	Workgroup member	A	A	A	A	AD
Paul Mott	EDF Energy	CMP265 Proposer	X	A	A	A	AD
Mark Cox	EDF Energy	Workgroup alternate	AO	X	X	X	X
Natasha Ranatunga	EDF Energy	Workgroup alternate	AD	X	X	X	X
Michael Davies	Eider Reserve Power	Workgroup member	A	A	A	AD	X
Nicholas Rubin	ELEXON	Observer	X	X	A	A	AD
John Lucas	ELEXON	Observer	X	A	X	X	X
Talia Addy	ELEXON	Observer	X	A	X	X	X
Kate Dooley	Energy UK	Observer	AD	X	AD	X	X
Simon Lord	Engie	Workgroup member	A	A	A	A	A
Stephen Davies	EON	Workgroup member	A	X	A	X	X
Brian Tilley	EON	Workgroup alternate	X	X	X	AO	X

Name	Organisation	Role	13/06/16 CMP265 14/06/16 CMP264	21/06/16	04/07/16	11/07/16	28/07/16 (teleconference)
Graz MacDonald	Greenfrog Power	Workgroup member	A	A	A	AD	AD
Christopher Granby	Infinis	Workgroup member	A	A	X	A	X
Lucas Lilja	Intergen	Observer	X	AD	X	X	AD
Bruno Menu	Lime Jump	Observer	X	X	X	X	X
Lars Weber	NEAS Energy	Workgroup member	A	A	A	A	X
Dominic Green	Ofgem	Observer	AD	A	A	X	AD
Dena Barasi	Ofgem	Observer	X	X	X	X	X
Jon Fairchild	Peakgen	Workgroup member	A	X	X	X	X
Mark Draper	Peakgen	Workgroup alternate	X	AO	AO	AO	AD
Bill Reed	RWE Npower	Workgroup member	A	A	A	A	AD
Herdial Dosanjh	Npower	Workgroup member	X	X	X	X	X
George Douthwaite	RWE Npower	Workgroup alternate	X	X	X	AO	AD
Fruzina Kemenes	RWE Npower	Workgroup alternate	X	AO	AO	X	AD
James Anderson	Scottish Power	Workgroup member	X	A	A	X	AD
Rupert Steele	Scottish Power	CMP264 Proposer	AO	X	X	AO	X
John Tindal	SSE	Workgroup member	A	A	A	X	AD
Gareth Graham	SSE	Workgroup alternate	X	X	X	AO	X
Kirsten Gardner	Stag Energy	Workgroup member	A	A	AD	A	AD
Jonathan Graham	The ADE	Workgroup member	A	X	A	A	AD
Tim Rotheray	The ADE	Workgroup alternate	X	AO	X	X	X
Sam Wither	UK Power Reserve	Workgroup member	X	X	X	A	AD
Ian Tanner	UK Power Reserve	Workgroup alternate	AO	AO	AO	AD	AD
Guy Phillips	Uniper	Workgroup member	A	A	A	AD	X
Paul Jones	Uniper	Workgroup alternate	X	X	X	X	AD
Lisa Waters	Waters Wye	Workgroup member	A	A	A	X	X
Matthew Tucker	Welsh Power	Workgroup member	A	A	A	A	X

7.4 What generators pay for use of the network

7.4.1 Transmission connected generation is subject to three types of transmission charges; connection charges, Transmission Network Use of System (TNUoS) charges and Balancing Services Use of System (BSUoS) charges. TNUoS recovers the cost of Transmission Owner activities for the three onshore TOs (National Grid, SHET and SPT), Offshore Transmission Owners (OFTOs) and the Network Innovation Competition; in future it is expected to also recover the costs of the Competitively Appointed Transmission Owner (CATO) regime for onshore competition, and interconnector cap and floor. BSUoS recovers the costs associated with balancing and operating the system for National Grid in its role as system operator. Connection Charges recover the cost of single user transmission assets for the onshore TOs.

7.4.2 Distribution connected generation is subject to three types of distribution charges: connection charges and Distribution Use of System (DUoS) charges. Distributed generation is potentially able to realise “TNUoS embedded benefit”, and as they contribute to reducing net demand, reduce liability for BSUoS, Assistance for Areas with High Electricity Distribution Costs (AAHEDC) Charge, and CM Supplier Levy.

7.4.3 Non-Exemptible distributed generation pays generation TNUoS does not receive embedded benefit. These generators will continue to need to be detailed in the datafiles so that can be treated appropriately.

7.4.4 Distribution Use of System (DUoS) Charges recover the cost of installing and maintaining the shared distribution system assets that cannot be attributed to a single user in England, Wales or Scotland. DUoS also recovers the cost of shared assets and maintaining and replacing sole use assets that are not recovered in the connection charge.

7.4.5 There is significant difference between the connection charging methodologies across transmission and distribution. Transmission connection charges are “shallow” and consist only of a small number of sole user assets such as a transformer. Any local circuit longer than 2km is charged through the TNUoS methodology. In addition, users have the choice to pay connection charges up front as a capital contribution, or over a period of 40 years. Users also pay for the maintenance of their connection assets over 40 years. Distribution connection charges are much deeper and consists of sole user’s works, a contribution towards shared assets and wider reinforcements. They must be paid up front, with the maintenance costs being recovered the DUoS.

7.5 Notes on RIIO allowances and allowed revenue

7.5.1 The total amount of money to be recovered in a given year under TNUoS is set according to allowed revenue. One of the items of interested to the workgroup was whether any of these costs could be attributed to specific activities within the TO.

7.5.2 At the highest level for the 2016/17 the total amount of revenue to be recovered through TNUoS is £2.7bn as shown in Table 16.

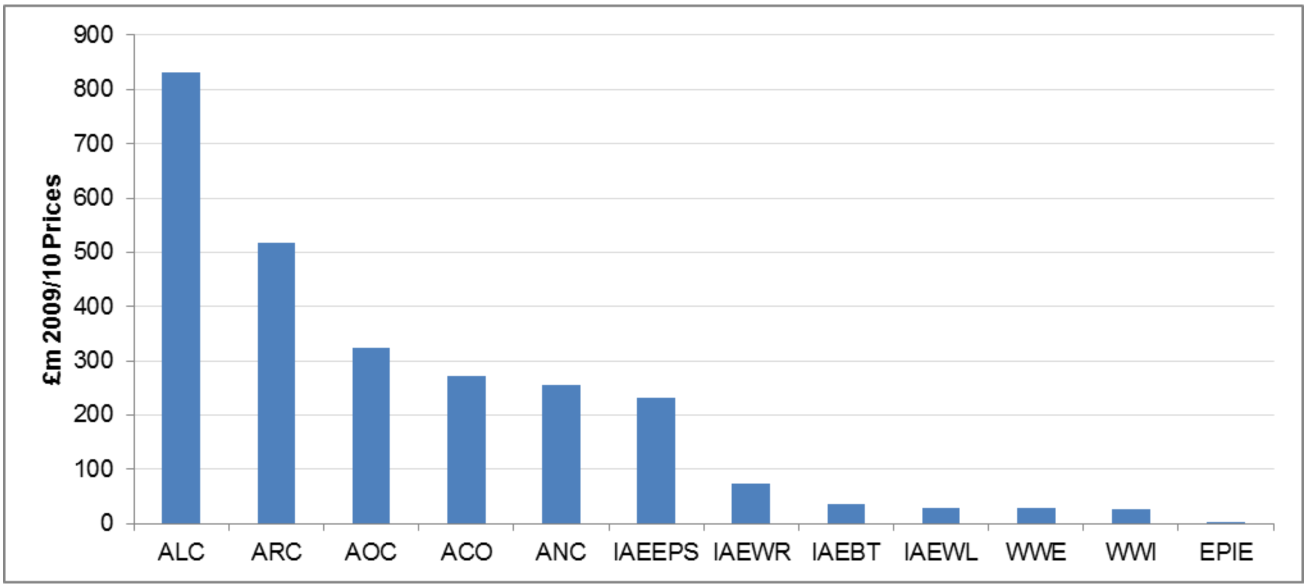
	2016/17 £m	%
National Grid	1,785.5	65.9%
Scottish Power Transmission	294.6	10.9%
SHE Transmission	322.8	11.9%
Offshore	260.8	9.6%
Network Innovation Competition	44.9	1.7%
Total to Collect from TNUoS	**2,709**	**100.0%**

Table 16: Total allowed revenues for 2016/17 TNUoS

7.5.3 It is also worth reflecting on what proportion of the, for example, National Grid £1.7bn is related to cost associated directly with maintaining and operating the network, and what are other costs as permitted by the RIIO Price Control

7.5.4 National Grid's allowed baseline revenue is £1675m, compared to a total of £1785m. The different is composed, in part, of Pass-through Costs (£7.7m) and Output Incentives (£13.9m) and a correction (Kt £56m) for under-recovered revenue from 2014/15 TNUoS tariffs). The vast majority is, however, based on the allowed revenue agreed as part of the Price Control. For further information refer to National Grid's Revenue Forecast in the 2016/17 Final Tariffs[48].

7.5.5 Under the RIIO-T1 price control, National Grid are allowed to expend so much money in a given year, and therefore entitled to a revenue based on that expenditure, performance, and historic investment. For 2016/17 the total amount of expenditure forecast by each of the onshore TOs is shown in Figure 14, with a total of £2.6bn in 2009/10 prices.



Key

ALC	Actual load related capex expenditure
ARC	Baseline and strategic wider works outputs
AOC	Network development and wider works volume driver (NGET only)

IAEWR	Actual other capex expenditure
IAEBT	Demand related infrastructure volume driver
IAEWL	Pension Scheme Established Deficit

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ACO	Generation connections volume driver	WWE	Actual non-operational capex
ANC	Actual controllable opex	WWI	Uncertain costs - enhanced security
IAEEPS	Actual asset replacement capex expenditure	EPIE	Pension scheme administration and Pension Protection Fund Levy

Figure 14: Components of allowed revenue under RIIO-T1 for 2016/17 in 2009/10 prices.

7.5.6 For each TO, these allowances are converted into a revenue stream - based on some fast-pot expenditure, and depreciation, revenue, and other allowances, as shown in Figure 15.

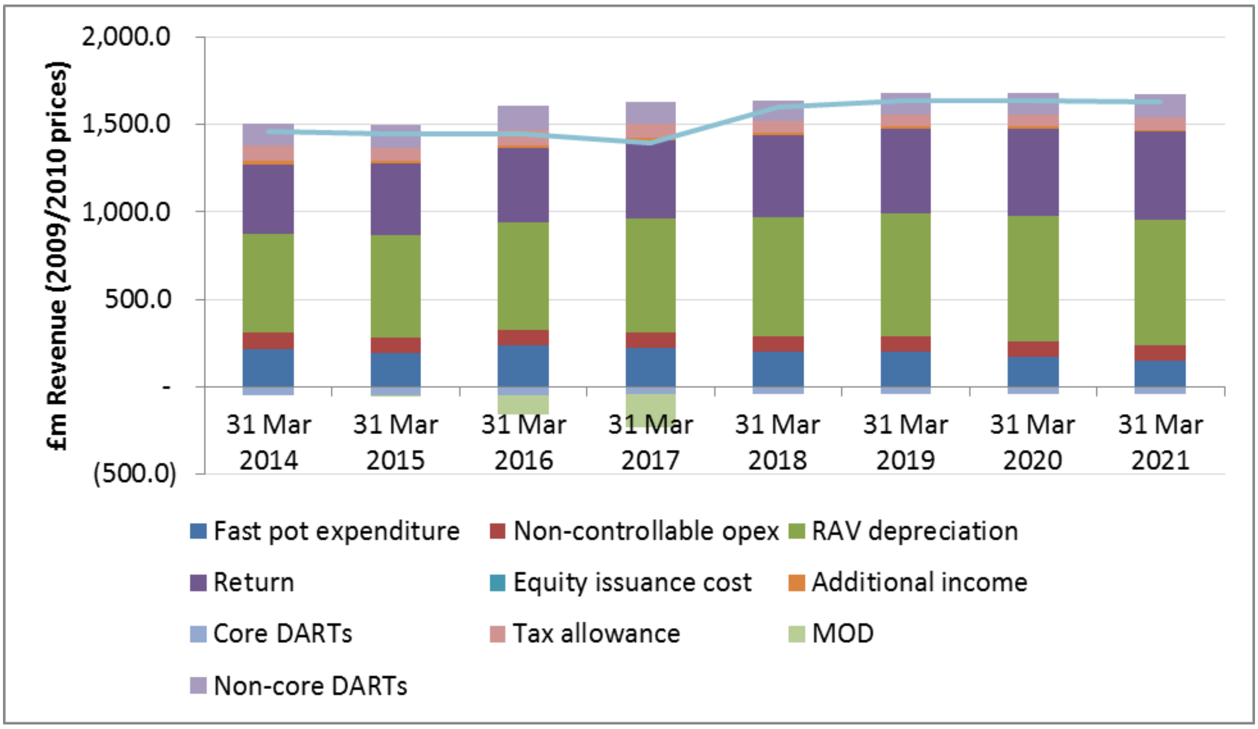


Figure 15: Baseline RIIO-T1 allowance, in 2009/2010 prices, for NGET.

7.6 Further information

Charging Year	2005/2006	2006/2007	2007/2008	2008/2009	2009/2010	2010/2011	2010/2011
Demand Residual (£/kW) 16/17 prices	15.50	16.75	18.36	19.28	20.39	22.45 [1]	20.61 [2]

Charging Year	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
Demand Residual (£/kW) 16/17 prices	22.8	25.10	27.07	31.08	35.99

Charging Year	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021
Demand Residual (£/kW) 16/17 prices	45.33	45.17	49.92	53.15	63.81

Notes
[1] This is the tariff set before the start of the charging year for 2010/11
[2] This is the revised tariff for 2010/11 adjusted part way through the year as a mid-year tariff change

Data for 2005/06 until 2016/17 is from actual set tariffs. Data from 2017/18 to 2020/2021 is from the Five-Year Forecast

Table 17: Historic and Forecast Demand Residual since 2005/06

7.7 Further information on Cost Reflectivity

7.7.1 The diagram shows the system used for the presentation with the main transmission system demand, generation and embedded generation represented by Fm , Tm and Em .

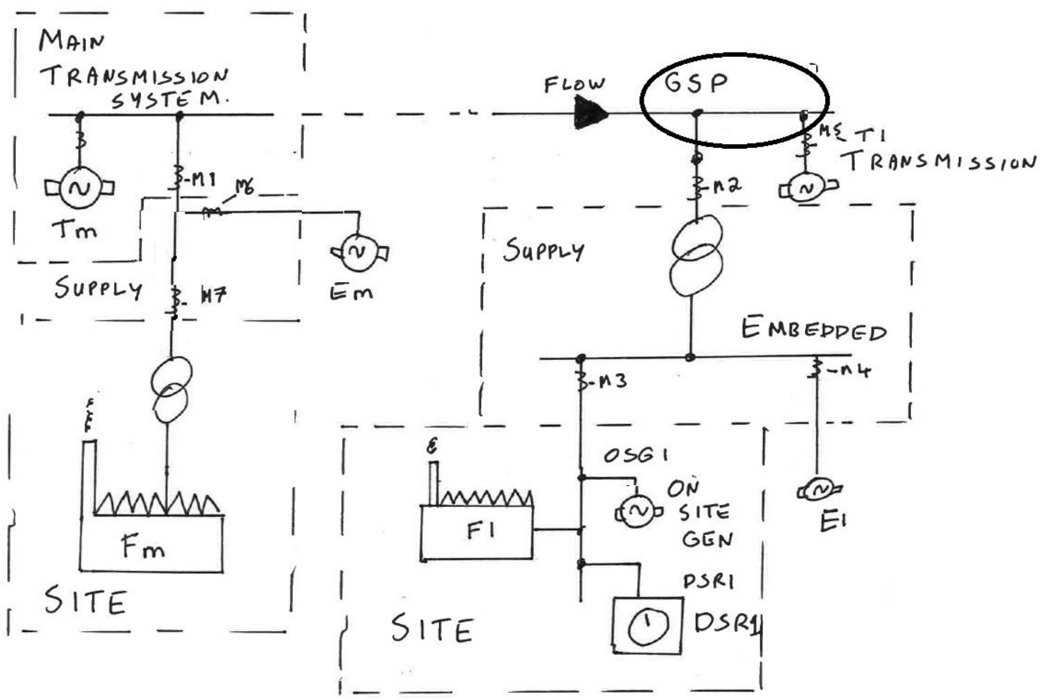


Figure 16: Example system – the focus is the circled GSP.

7.7.2 A small node (GSP) on the system was then examined that contains a 1000MW of demand (F1) . 100MW of generation/demand reduction is placed at four below the GSP to replicate, supplier connected embedded generation (E1), one site generation (OSG1) , demand side response (DRS1) and transmission connected generation (T1) at the same GSP.

7.7.3 The MW assumptions for each load/generator is shown below. Meters are allocated as required but principally at boundaries to the supplier zones. The numbers used are representative of the actual demand /supply and costs at peak.

	Base asumptions		Base	Transmission	Embeded	DSR	OSG
Demand	Demand	Fm (M7)	56000	56000	56000	56000	56000
		F1	1000	1000	1000	1000	1000
Generation	Transmission	Tm (slack Bus)	-50100	-50000	-50000	-50000	-50000
		T1 (M5)	0	-100			
	Embeded	Em (M6)	-6900	-6900	-6900	-6900	-6900
		E1 (M4)			-100		
	DSR	DSR1				-100	
	On site gen	OSG1					-100
	=Fixed	Changes					

Figure 17: Base flow under this model

7.7.4 The output from the model for the four scenarios are shown below based on increment 100 MW.

				Base	Transmission	Embeded	DSR	OSG
Transmission Demand (M1 + M2)			MW	50100	50100	50000	50000	50000
Supplier Demand (M7 + M2)			MW	57000	57000	57000	56900	56900
Transmission Cost			£m	2275	2275	2275	2275	2275
Rate			£/kw	45.41	45.41	45.50	45.50	45.50

				Base	Transmission	Embedded	DSR	OSG
Flow (MW)				1000	900	900	900	900
Transmission Customer Cost(Fm+F1)			£m	2588.32	2588.32	2593.50	2588.95	2588.95
F1 cost			£m	45.41	45.41	45.50	40.95	40.95
E1+Em Cost			£m	-313.32	-313.32	-318.50	-313.95	-313.95
Delta Transmission Cost (100MW)			£m	NA	0.00	5.18	0.63	0.63
Delta F1 Cost			£m	NA	0.00	0.09	-4.46	-4.46
DSR/onsite payment [50/90%] of benefit			£m				2.23	4.01
Customer cost + DSR/onsite payment			£m	2588.32	2588.32	2593.50	2591.18	2592.96
Delta cost			£m		0.00	5.18	2.86	4.64

Figure 18: Updated flows under this model

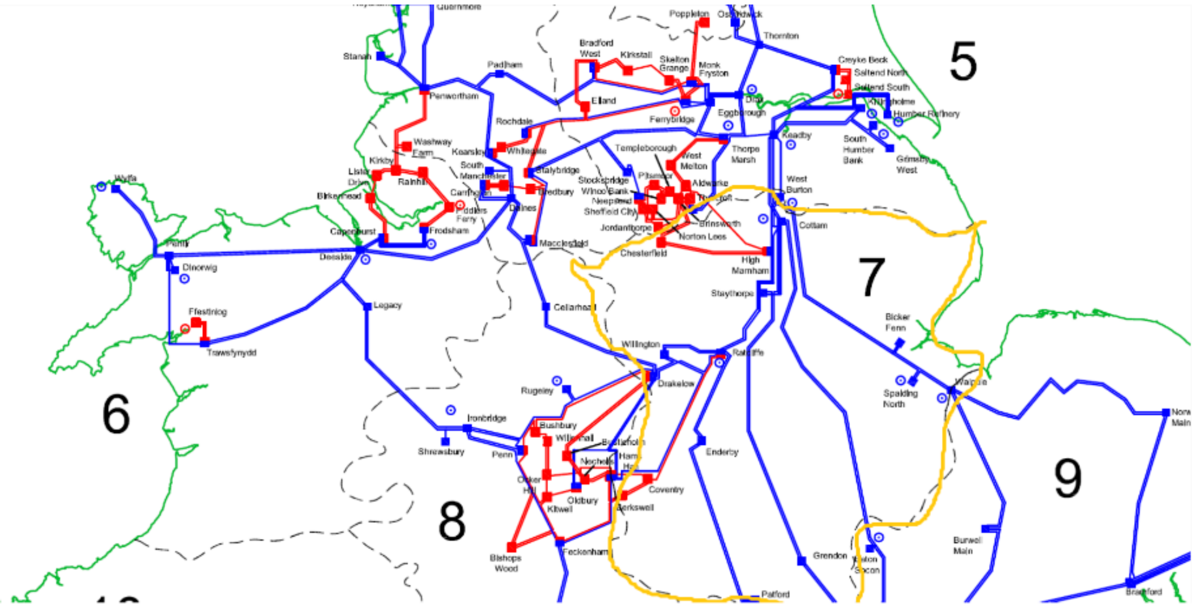
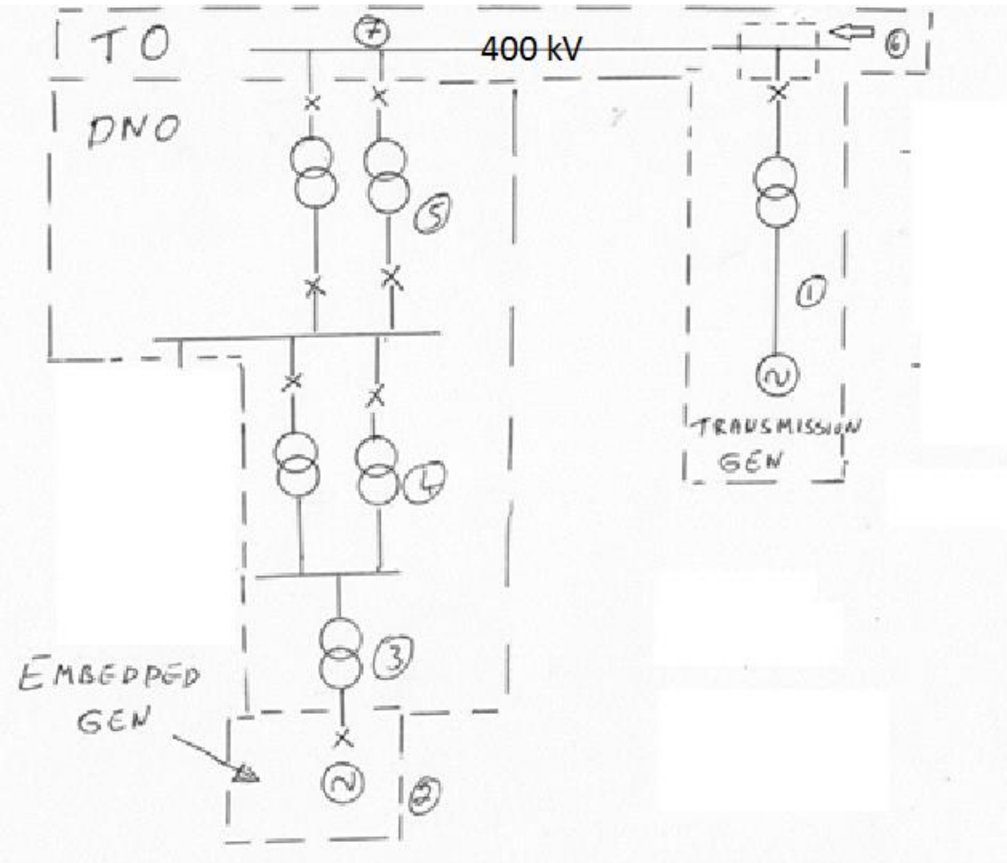


Figure 19: Demand Zone 7

DC Load Flow							
Nodal Input							
Bus ID	Bus Name	Voltage	Demand	Cat A Gen	Gen Zone	Dem Zoi	delta MWkm
47	BICF4A	400	83	0	16	7	214.56
48	BICF4B	400	83	0	16	7	208.20
121	CHTE20	275	503	0	16	7	212.80
147	COTT40	400	0	2,395	16	7	259.58
368	HIGM20	275	0	0	16	7	263.56
369	HIGM40	400	0	0	16	7	249.77
695	STAY40	400	181	1,728	16	7	216.59
696	STAY4A	400	0	0	16	7	200.57
777	WBUR40	400	260	3,292	16	7	272.13
859	HIGM4A	400	0	0	16	7	239.44
860	HIGM2A	400	0	0	16	7	249.77
MWkm			227.1	255.1			
689	SPLN40	400	0	880	17	7	196.96
767	WALP40_EME	400	245	2,314	17	7	171.35
MWkm			171.3	246.3			
46	BESW20	275	334	0	18	7	-50.20
149	COVE20	275	487	0	18	7	-26.76
193	DRAK20	275	186	0	18	7	103.49
194	DRAK40	400	0	1,320	18	7	83.20
223	ECLA40_EME	400	392	0	18	7	0.00
245	ENDE40	400	550	0	18	7	86.55
326	GREN40_EME	400	671	401	18	7	87.74
349	HAMH40_EME	400	119	0	18	7	41.82
581	PAFB4A	400	0	0	18	7	45.09
582	PAFB4B	400	15	0	18	7	45.17
624	RATS2A	275	0	0	18	7	98.30
625	RATS40	400	435	2,021	18	7	123.67
647	SBAR40	400	154	0	18	7	171.38
802	WILE20	275	302	0	18	7	90.85
803	WILE40	400	302	0	18	7	90.85
MWkm			59.9	105.5			

Figure 20: Nodal cost in Demand 7 illustrating there are both positive (requiring generation), negative (requiring demand) and near zero (more balanced) nodes within one large zone.



Key

Key	Typical funding arrangements for connections
1	Transmission generator owner
6	TO owned securitised by Transmission generator
2	embedded generator owned
3	Sole works funded by embedded generator
4	Reinforcement funded by embedded generator
5	Reinforcement funded by embedded generator
7	Exporting GSP's no embedded generator funding

Figure 21: Comparison of Transmission and Distribution Assets